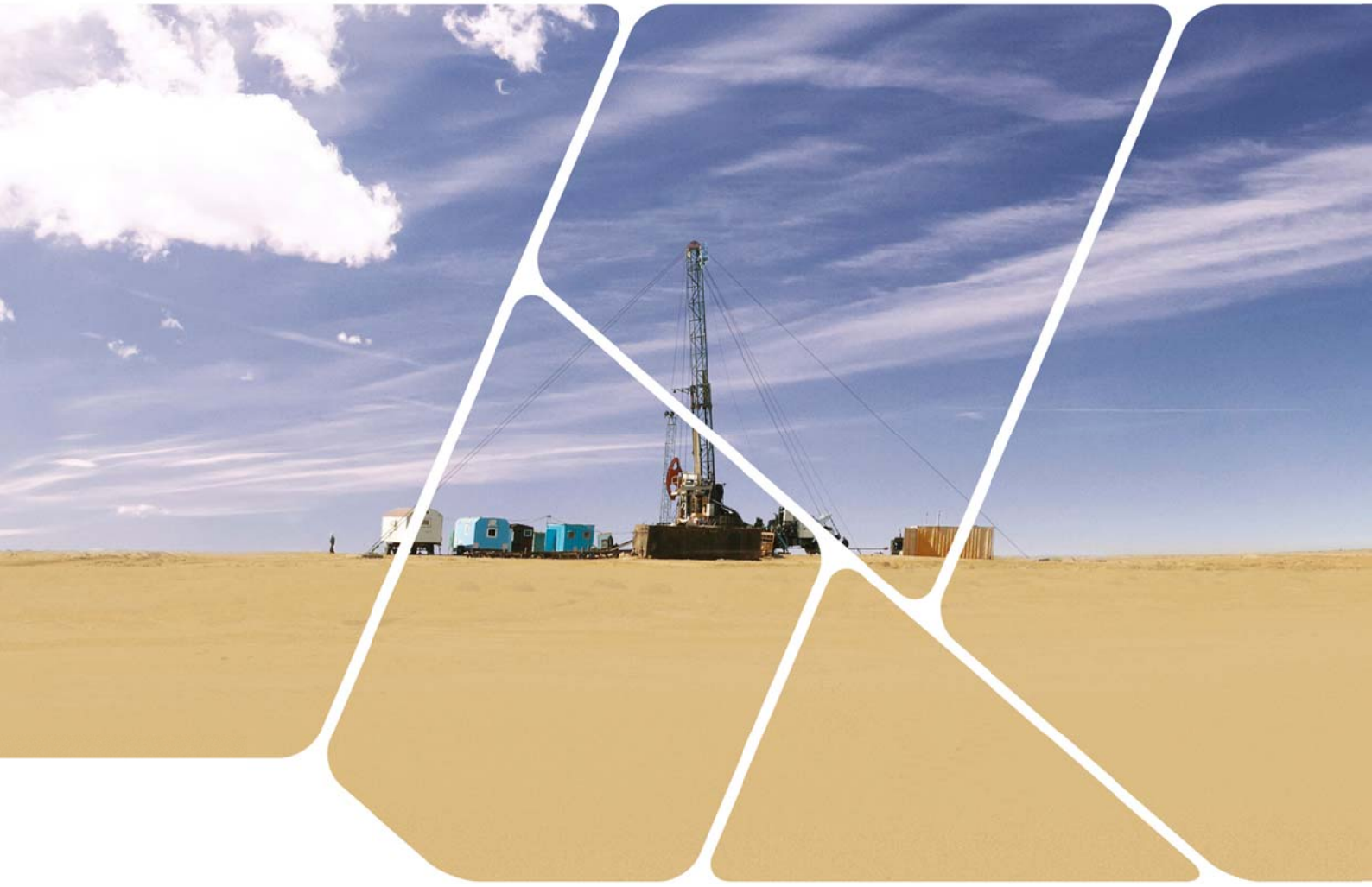


RESERVOIR ENGINEERING GRADUATE CERTIFICATE - *Week 10 & 11*

Dynamic Reservoir simulation

A special course by IFP Training for REPSOL ALGERIA
Alger – January 15 to 26, 2017

ifptraining.com

Course summary

- Reservoir simulation workshop Introduction 3
- Reservoir simulation workshop Simulator presentation 91
- Dynamic reservoir simulation Data review: gridding 139
- Dynamic reservoir simulation Data review: PVT 226
- Dynamic reservoir simulation Data review: Initialization 298
- Dynamic reservoir simulation Data review: Aquifers 318

- Dynamic reservoir simulation Data review: Flow description 346
- Dynamic reservoir simulation Data review: Well representation 408
- Reservoir simulation workshop History match 471
- Reservoir simulation workshop Production forecast 521



An IFP Training Course for REPSOL

Reservoir simulation workshop
Introduction

Instructor: Maria AGUILERA

IFP Training

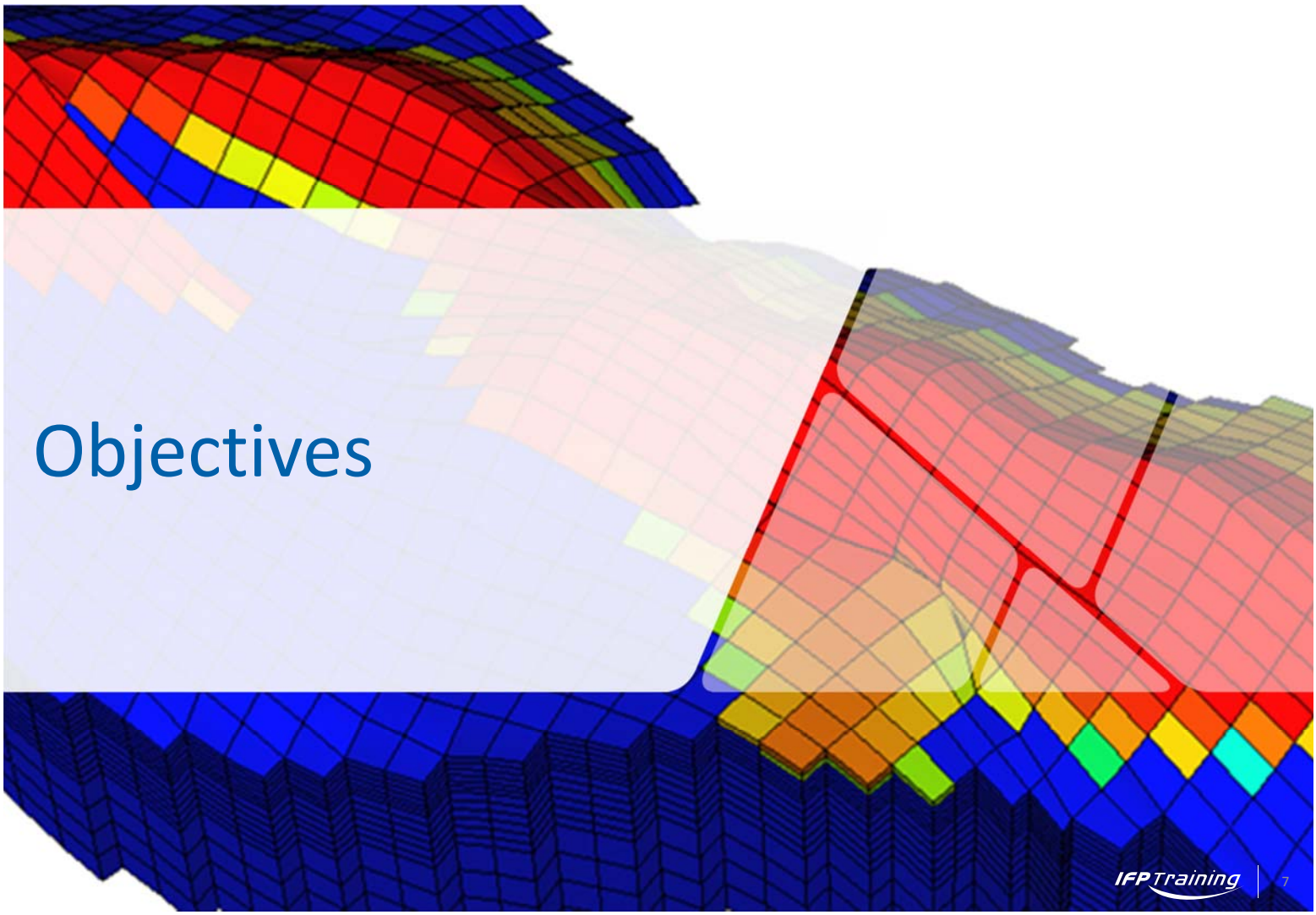
Course outline

- **Introduction**
- **Simulator presentation**
- **Data review**
  - Reservoir description – Gridding
  - Fluid description
  - Initialization
  - Aquifers
  - Flow description
  - Well representation
- **History matching**
- **Production forecasts**

IFP Training

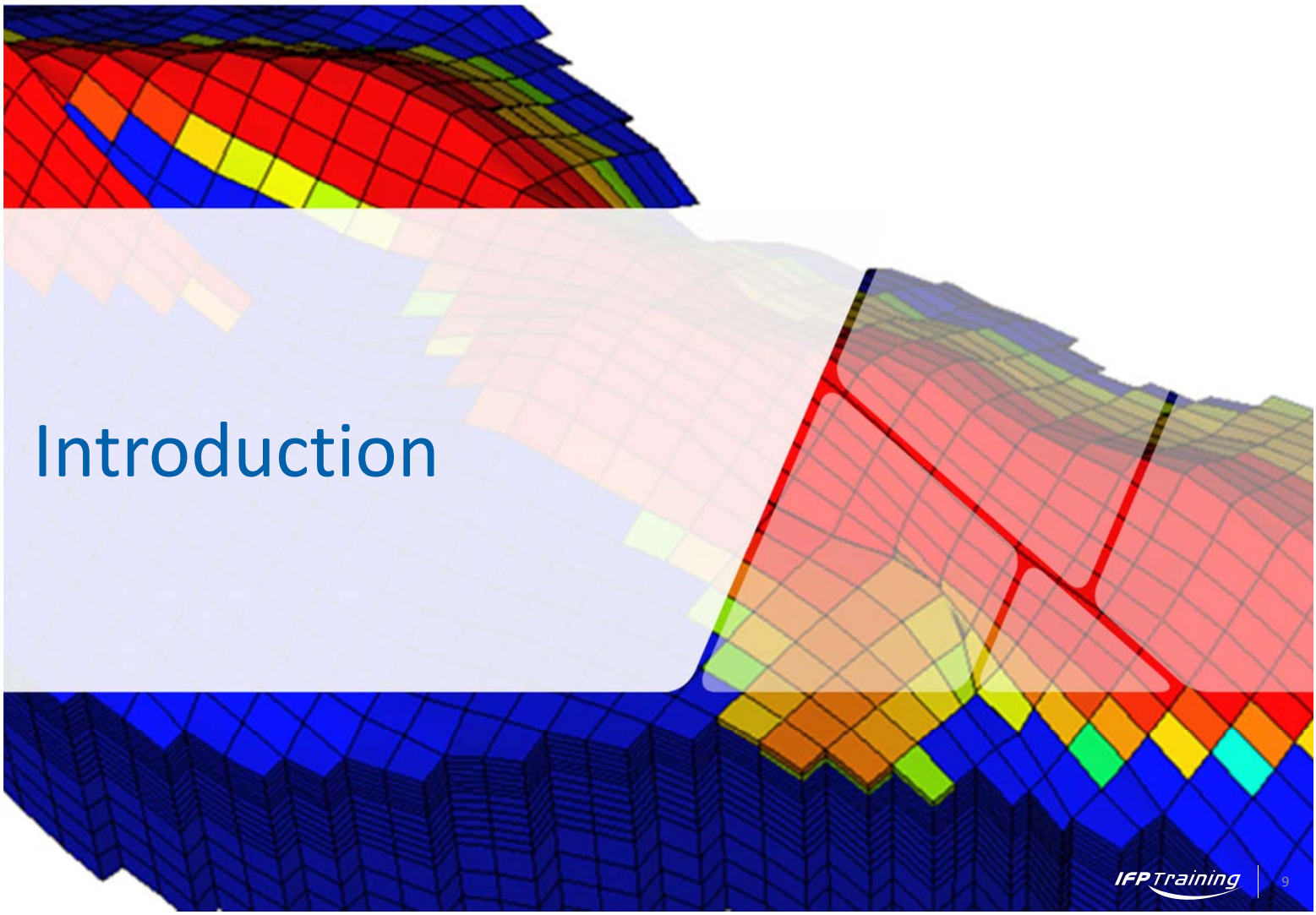
Chapter 1

- **Objectives** 7
- **Introduction** 9
- **Why run a reservoir simulation** 65
- **General workflow and data review** 77



Objectives

- **Introduce you to the basic concepts of modelling**
- **Introduce you to the numerical reservoir modelling capabilities, and major features**
- **Illustrate with some results, with examples and exercises**
- **By the end of this lecture, you should be aware that:**
  - Simulation is a useful reservoir engineering tool
  - A model must not be used as a black box
  - The output results depend upon the quality of the input data
  - What goes in → what comes out!!!



Reservoir Simulation

What is Dynamic Reservoir Simulation?

- Reservoir simulation is an area of reservoir engineering in which computer models are used to predict the flow of fluids (typically, oil, water, and gas) through porous media, before deciding on a development plan and investment strategy
- Simulation is a reservoir engineering tool; it is the most powerful tool in the reservoir modeling tool box.
- Reservoir simulation associated with material balance study are the basic techniques an engineer must be familiar with.

Dynamic reservoir simulation

- **Early in a fields life, it is essential to be able to evaluate how much Hydrocarbons will be produced through time:**
  - How much hydrocarbon is in the reservoir?
  - How much of that hydrocarbon can potentially be recovered?
  - How quickly can the recoverable hydrocarbons be produced?
  - How will the reservoir perform under various development scenarios?
- **A Dynamic Reservoir Model is a useful tool that may help to answer those questions.**

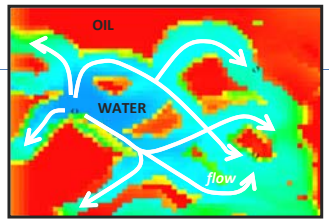
Why reservoir simulation...

- **Main drivers:**
  - To overcome simplifying assumptions (used in hand calculations)
  - To consider realistic problems (development plan, production history)
  - To take into account all the available data and to better understand all the interactions between them for a given scenario
  - To perform sensitivity to unknown parameters
- **Main use:**
  - Help to decision, in particular at the end of appraisal phase and during pre-development screening
  - Optimize the production profile and the final recovery after production start-up by improving the reservoir description
  - Establish of reliable production forecasts

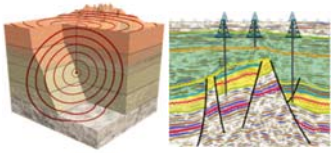
Why reservoir simulation...

- **Appraisal**
  - To identify dynamic incertitude
  - To define appraisal needs (contacts, faults, facies variations)
- **Non producing reservoir: Field development plans**
  - To identify efficient recovery mechanisms
  - To define the well number, their location and their architecture
  - To give production profiles to decision makers
  - To appreciate the risks associated to the project
  - To optimize Capex
- **Producing reservoir or Mature fields**
  - To improve the reservoir characterization through history matching
  - To give production profiles (oil, gas and water flow rates, pressure, fluid composition, …) associated to existing wells
  - To define completion changes or infill drilling
  - To optimize oil production and recovery
  - Optimize field capacities (treatment capacities, compressors, …)
- **In all cases**
  - To establish reliable production forecasts

Reservoir simulation...

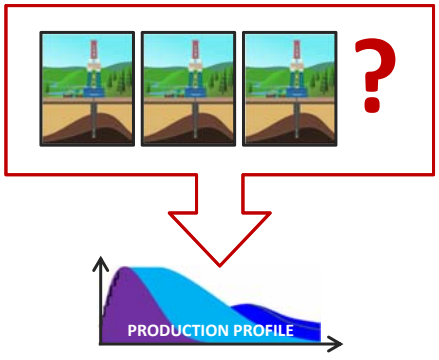


APPRAISAL / DELINEATION



DEVELOPMENT

DECISION MAKING

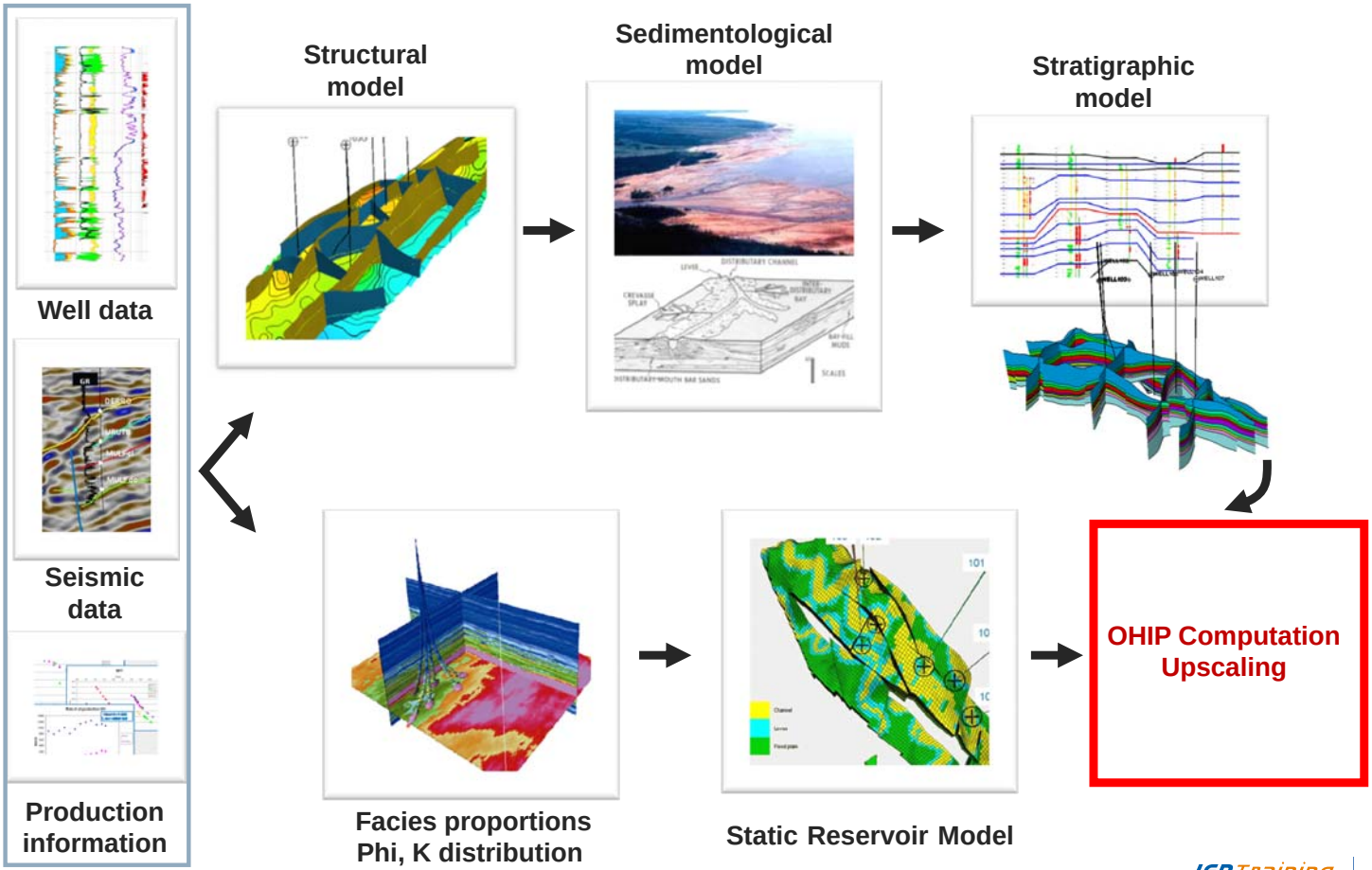


Reservoir simulation model

Data set workflow

- **Reservoir characterization**
  - Depositional environment, structure, rock and fluid properties
- **Geological model**
  - Fine grid model filled up by automatic distribution methods; calculation of hydrocarbons in place volumes
- **Upscaling process**
  - Average small cells properties to fill up larger cells
- **Reservoir simulation model**
  - Coarse grid model for history match and prediction runs

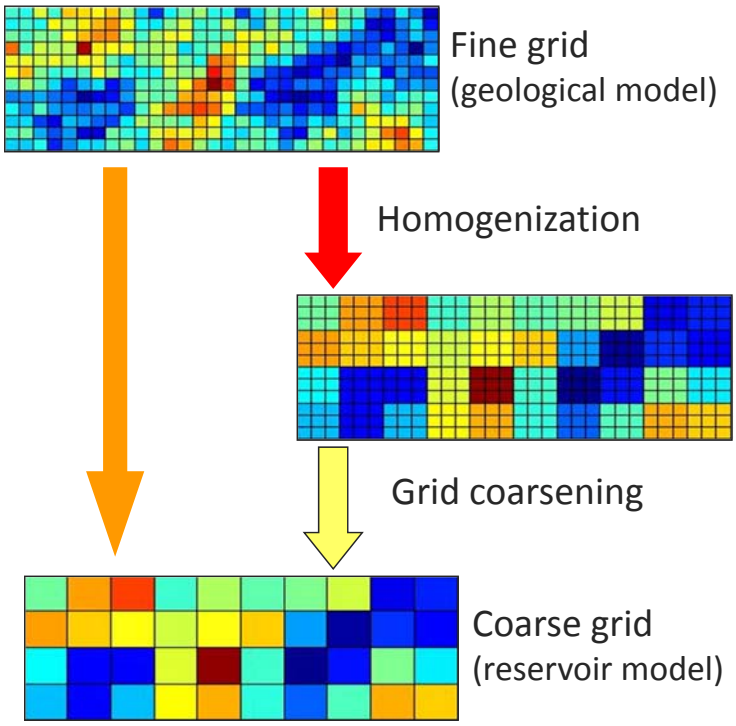
Reservoir modeling workflow



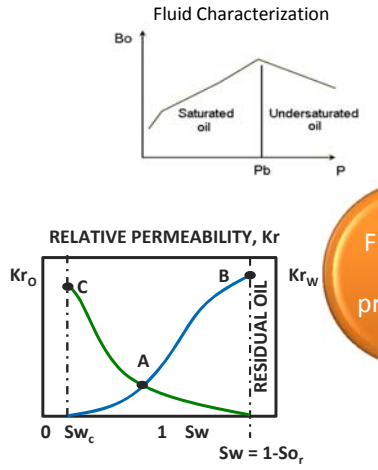
Upscaling

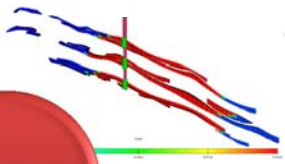
- **Geological model contains a very large number of grid blocks. This level of resolution is generally incompatible with the computing capabilities of numerical flow simulators.**

- **To do so, fine grid blocks are grouped in aggregates: coarse grid blocks. The basic problem is to determine the equivalent properties of the coarse gridblocks.**



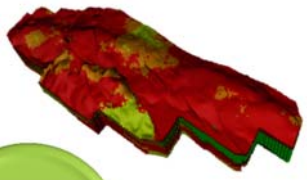
Reservoir simulation model





Wells

Type of well
Completion
Schedule



Structural model
Stratigraphic and Layering Model
Rock Type
Facies and Properties population
OHIP Evaluation
Upscaling

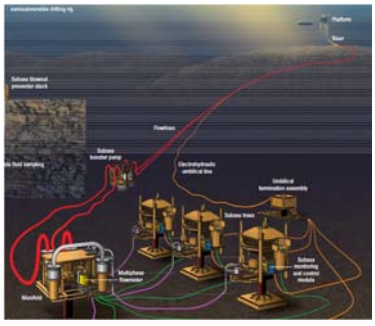
Fluid and flow properties

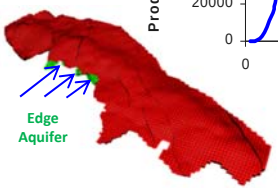
Geological model

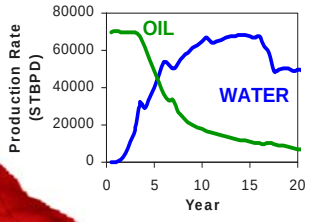
Reservoir Simulation Model

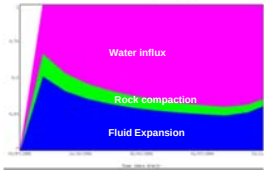
Surface facilities

Production data









Natural Drive Understanding
Drive Mechanisms
Aquifer Model ?
Production/Injection Data

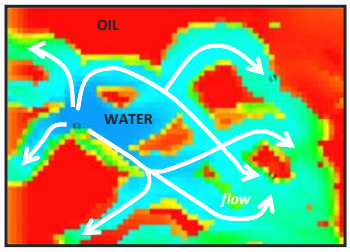
Reservoir simulation model

=

Numerical simulator

+

Set of data



- **Modeling: building the model (define parameters through integrated reservoir characterization studies, choose physical options)**
- **Simulation: running the model, either in history matching simulations or in forecast simulations**

- **What is Reservoir Simulation?**
- **What is a Numerical Simulator?**

- **Reservoir Simulation**
  - Is an approach that enables the reservoir engineer to analyse phenomena that could not be described by simple “hand calculations” or “traditional calculations”, due to their complexity

- **A Numerical Simulator**
  - Is a numerical model translating the image of our understanding of the reservoir into mathematical equations

Reservoir simulation models

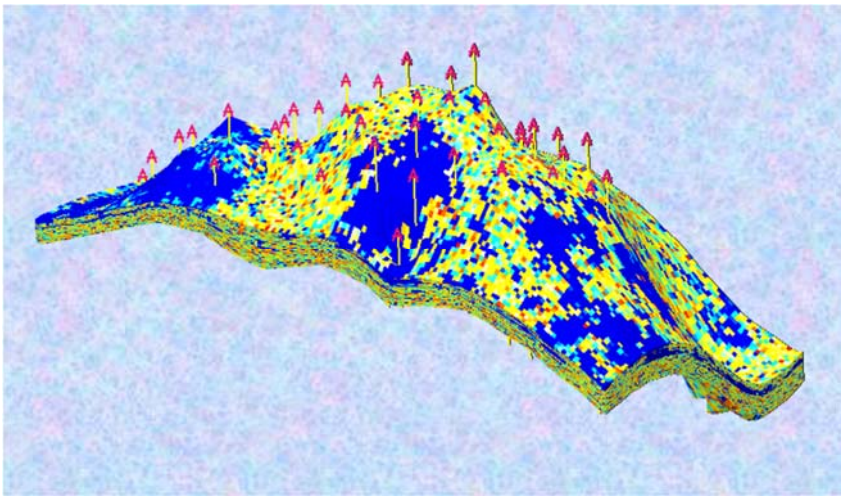
- **A reservoir model is a mathematical representation or translation of the image that geoscientists and reservoir engineers have of a reservoir**
- **Numerical simulations allow reservoir engineers to understand processes that are in action in the reservoirs and to predict reservoir behaviour under various production scenarios**
- **Human factor is therefore an important aspect of reservoir simulation:**
  - A potential risk would be that users could consider their results as “representing the reality”…
  - Users experience is therefore an essential aspect in reservoir simulation

Reservoir simulation models

- **A model is a simplified representation of the reality which allows the study of physical phenomena**
- **A model may be viewed as a transfer box receiving inputs and delivering outputs but:**
  - Some principles must be clearly recognized:
  - The model must not be used as a black box
  - The output data cannot be better than the input data
- **To be useful in reservoir studies, a model must be workable (size, time and cost) and trustable (acceptable accuracy)**

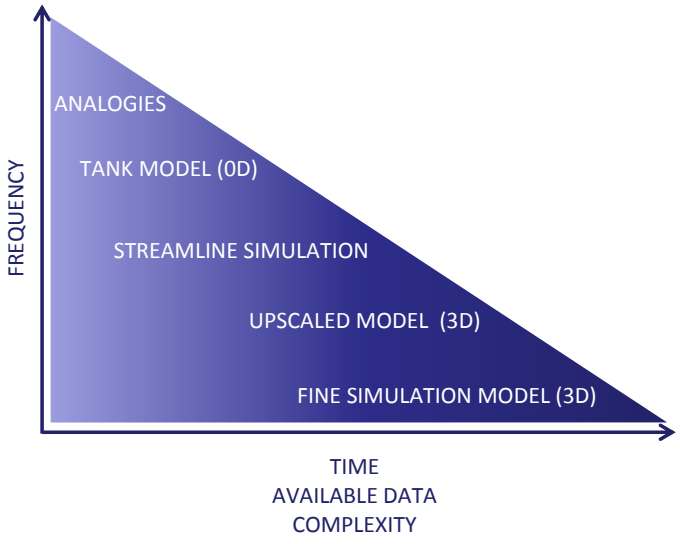
Types of simulators

- **Mass balance simulator (ex.: MBAL)**
- **Numerical simulator (ex.: ATHOS, ECLIPSE, VIP…)**
  - Single phase
  - Black Oil
  - Compositional
  - Chemical
  - Thermal
  - Fractured

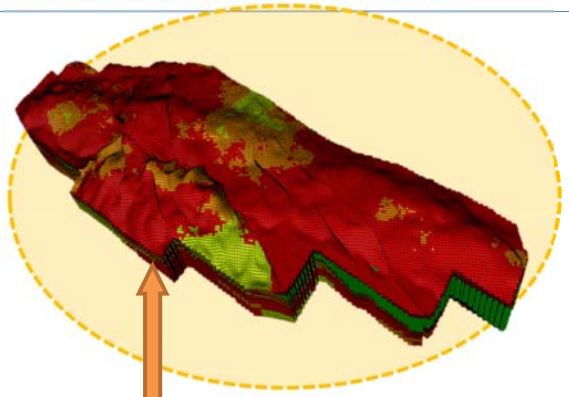


Reservoir Model Selection

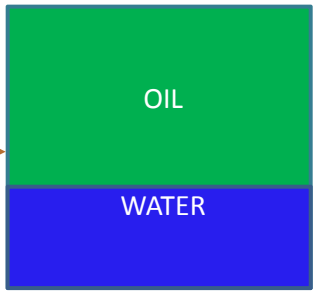
- **Not every question needs in-depth modelling**
- **The model selection will depend on:**
  - Scope
  - Process
  - Available data
  - Resources (time, budget, software)



Mass balance simulator



OHIP, ϕ, K, NTG, Swi



THE RESERVOIR IS REPRESENTED BY A TANK WITH A UNIQUE POROSITY, PRESSURE, SATURATION

- Very simple model
- Material balance equation
- Checking data consistency
- Determine fluids in place
- Estimate aquifer type and size
- Production prediction

Mass balance simulator

Material balance equation

$$N.Bo_i = (N - Np)Bo + [(N.Rs_i - Gp) - (N - Np)Rs]Bg$$
$$+m.N.Bo_i\left(\frac{Bg}{Bg_i} - 1\right) + We - Wp.Bw$$

Introducing *Rp* definition: $Rp = \frac{Gp}{Np}$

$$Np[Bo + (Rp - Rs)Bg] = N[(Bo - Bo_i) + (Rs_i - Rs)Bg]$$
$$+m.N.Bo_i\left(\frac{Bg}{Bg_i} - 1\right) + We - Wp.Bw$$

Mass balance simulator

- **Material Balance is suggested as a necessary step prior to carrying out a simulation study.**
- **Material balance will always enable the drive mechanisms to be identified.**
- **A material balance study can provide OHIP and drive mechanisms as inputs to simulation.**

Numerical simulators

Types

- **There are several types of numerical simulators**
  - Black oil: One porous medium + black oil functions
  - Compositional simulator: One porous medium + EOS
  - Dual porosity simulator: Two porous media (matrix and fractures)
  - Thermal simulator: Flow + Energy equations.

- **A numerical simulator also integrates specific features such as:**
  - Grid geometry (1D, 2D, 3D, CPG...).
  - Time step management.
  - Numerical schemes (discretization of equations).
  - Resolution methods.
  - Pressure drops through tubing and surface network.
  - Well schedule.

Basic equations

- **Reservoir (volumetric):** $dV_p = C_p V_p dP$
- **Fluids (volumetric):** $d\rho_f = -C_f \rho_f dP$
- **Fluids (compositions):** $\sum x_i = \sum y_i = 1, \quad \frac{x_i}{y_i} = K_i$
- **Darcy's law (one phase flow):** $\Delta(P - \rho.g.z) = -\frac{Q.\mu}{K.A}\Delta x$
- **Multi phase flow:** $\Delta(P_i - \rho_i.g.z) = -\frac{Q_i.\mu_i}{K.kr_i.A}\Delta x$

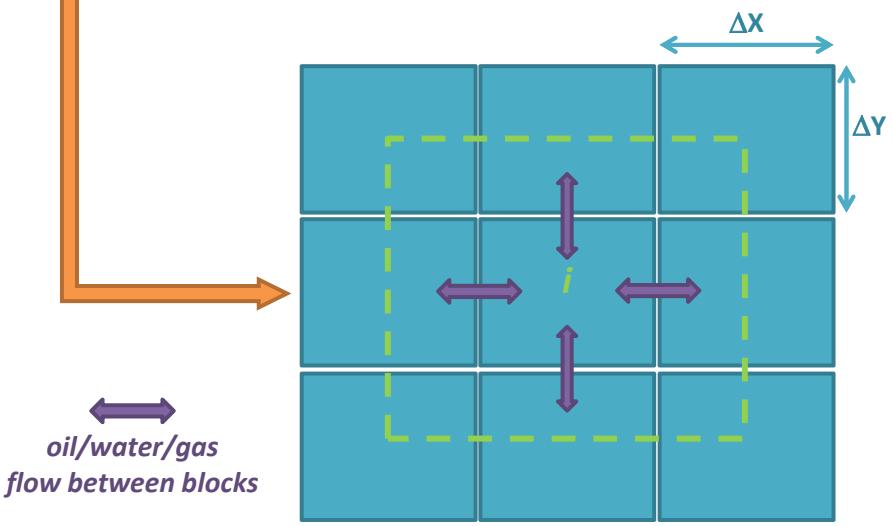
Basic parameters

- **Reservoir (volumetric)**
  - gross volume: Vt
  - net volume: Vu
  - porous volume & pore compressibility: Vp, Cp
- **Fluid**
  - saturation: So, Sg, Sw
  - density: ro, rg, rw
  - viscosity: µo, µg, µw
  - compressibility: Co, Cg, Cw
  - compositions: xi, yi, Ki
- **Flows**
  - permeability: K
  - capillary pressure: Pcwo = Po – Pw , Pcgo = Pg - Po
  - relative permeability: krow, krw, krog, krg

Numerical simulators



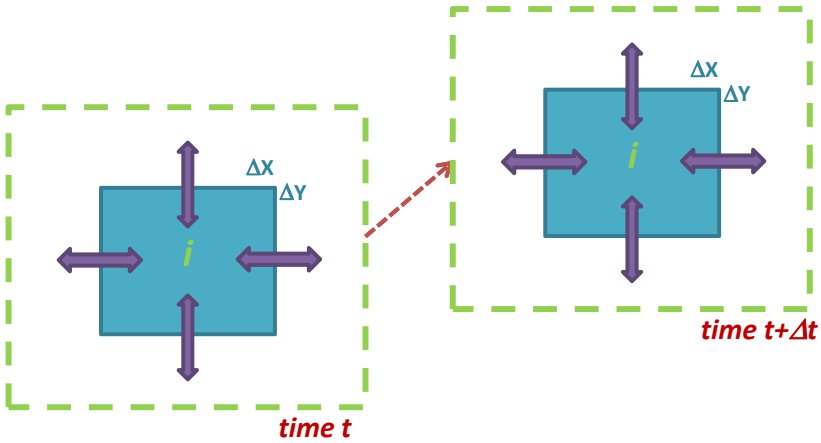
- Space discretization
- Material balance equation per block
- Properties distribution per block



material balance in the block 'i'

Numerical simulators

material balance in the block 'i'



$$(flow\ in) - (flow\ out) \pm (production\ or\ injection\ term) = accumulation\ term$$

$$\sum Q_{in} - \sum Q_{out} \pm q_i = \frac{\Delta m_i}{\Delta t}$$

MATERIAL BALANCE FOR EACH COMPONENT:

BLACK OIL MODEL: **OIL, WATER AND GAS**

COMPOSITIONAL MODEL: **C1, C2, C3, C4... Cn**

Basic equations: The flow term

$$Q_o^{ab} = \frac{\rho_{o,s}}{B_o} \frac{K^{ab}.A^{ab}}{L^{ab}} \frac{kr_o^{ab}}{\mu_o} (P_o^b - P_o^a - \rho_o.g.\Delta z^{ab})$$

$\rho_{o,s}$ = stock tank oil density

ρ_o = reservoir oil density

P_o^a, P_o^b = oil pressure of cells 'a' and 'b'

$\Delta z^{ab} = z^a - z^b$, depths of cells 'a' and 'b'

g = gravity accelerati on

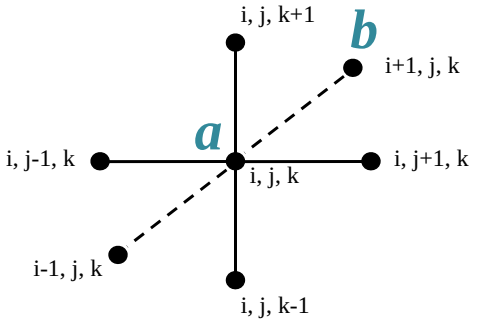
K^{ab} = permeabili ty
A^{ab} = flows section area
L^{ab} = distance

transmissivity

between cells 'a' and 'b'

kr_o = relative permeabili ty
μ_o = viscosity
B_o = formation volume factor

of oil between cells 'a' and 'b'



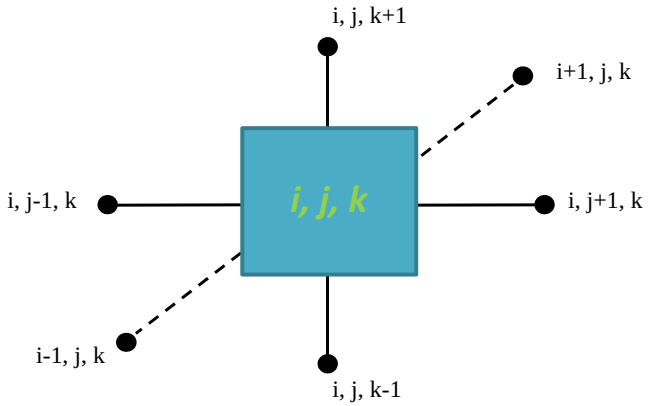
Basic equations: The accumulation term

$$\Delta m_o^i = \Delta(V^i, \phi^i, \rho_o^i, S_o^i)$$

$$\Delta m_o^i = V^i \left[S_o^i \left(\rho_o^i \frac{\Delta \phi^i}{\Delta P} + \phi^i \frac{\Delta \rho_o^i}{\Delta P} \right) \Delta P_o^i + \phi^i \rho_o^i \Delta S_o^i \right]$$

V^i = volume
ϕ^i = porosity
ρ_o^i = oil density
S_o^i = oil saturation

of cell 'i'



Numerical simulators

Production / injection terms

- **Constant well production rate. If the well is specified to have a constant well rate of Qi at reservoir conditions:**

$$q_i' = Q_i \cdot B_i$$

- **Constant well bottom hole pressure. For a well producing or injecting at a constant bottom hole pressure, Pbhi , the well rate is computed the following equation:**

$$q_i' = \frac{PI_i \cdot (P_i - P_{bhi})}{\mu_i \cdot B_i}$$

where PIi is the productivity or injectivity index of the well.

- **The PI may be specified externally, based on tests of the well. If the well is in the middle of the grid block, one may assume radial flow into the well, with block volume as the drainage volume:**

$$PI_i = \frac{2\pi \cdot k_i \cdot h}{\ln(r_e / r_w)}$$

Numerical simulator

Black oil model

- **Black-oil simulation means that the fluid properties depend only on pressure. They do not depend on the composition of that fluid**

  - Simplified fluid description PVT – (Black Oil)
  - Reservoir rock properties / Petrophysics (K, ∅, Cp)
  - SCAL (Kr – Pc)
  - Boundary conditions: wells and aquifers
  - Initial reservoir condition

Black oil model

- **Main assumptions**
  - 3 components (in standard conditions)
    - Oil & gas compositions are assumed constant in time
    - Oil, water & gas density are assumed constant in time
  - 3 phases (in reservoir conditions)
    - Oil is a mixture of "oil" & "gas" components
    - Gas corresponds to "gas component"
    - Water corresponds to "water component"
- **3 flow equations**
  - Oil equation
    - correspond to "oil component" contained in oil phase
  - Gas equation
    - correspond to "gas component" contained in oil & gas phases
  - Water equation
    - correspond to "water component" contained in water phase

Black oil model: densities

- **One phase gas: The gas must be single phase in the reservoir, which means that crossing of the dew point line is not permitted in order to avoid condensate fallout in the pores.**

$$\rho_g = \frac{\rho_{gs}}{B_g} = \frac{constant}{B_g}$$

- **One phase water: Strictly speaking, it means that Pres > Psat of the water, has a density described by:**

$$\rho_w = \frac{\rho_{ws}}{B_w} = \frac{constant}{B_w}$$

- **One phase oil: Oil must be undersaturated, which means that the Pres > Pb. In the Black Oil fluid model:**

$$\rho_o = \frac{\rho_{os} + \rho_{gs} \cdot R_s}{B_o}$$

for undersaturated oil, Rs is constant, and the oil density may be written:

$$\rho_o = \frac{constant}{B_o}$$

Numerical simulators

Black oil: The oil component flow equation

$$\sum_b \frac{\rho_{o,s}}{B_o} \frac{K^{ab}.A^{ab}}{L^{ab}} \frac{kr_o^{ab}}{\mu_o} (P_o^b - P_o^a + \rho_o.g.\Delta z^{ab}) = \Delta m_o^a$$

$$\Delta m_o^a = V^a \left[S_o^a \left(\rho_o^a \frac{\Delta \phi^a}{\Delta P} + \phi^a \frac{\Delta \rho_o^a}{\Delta P} \right) \Delta P_o^a + \phi^a \rho_o^a \Delta S_o^a \right]$$

Numerical simulators

Black oil: The water component flow equation

$$\sum_b \rho_w \frac{K^{ab}.A^{ab}}{L^{ab}} \frac{kr_w^{ab}}{\mu_w} (P_w^b - P_w^a + \rho_w.g.\Delta z^{ab}) = \Delta m_w^a$$

$$\Delta m_w^a = V^a \left[S_w^a \left(\rho_w^a \frac{\Delta \phi^a}{\Delta P} + \phi^a \frac{\Delta \rho_w^a}{\Delta P} \right) \Delta P_w^a + \phi^a \rho_w^a \Delta S_w^a \right]$$

Numerical simulators

Black oil: The gas component flow equation

$$\sum_b \rho_{g,s} \frac{K^{ab}.A^{ab}}{L^{ab}} \left[\frac{kr_g^{ab}}{B_g.\mu_g}(P_g^b - P_g^a + \rho_g.g.\Delta z^{ab}) + Rs \frac{kr_o^{ab}}{\mu_o}(P_o^b - P_o^a + \rho_o.g.\Delta z^{ab}) \right] = \Delta m_g^a$$

FREE GAS

DISSOLVED GAS

$$\Delta m_g^a = V^a \Delta(\phi^a(\rho_g^a.S_g^a + \rho_{g,s}.Rs.S_o^a))$$

$$\Delta m_g^a = V^a(\rho_g^a.S_g^a + \rho_{g,s}.Rs.S_o^a)\Delta\phi^a + V^a\phi^a\left[\left(S_g^a\frac{\Delta\rho_g^a}{\Delta P} + S_o^a.\rho_{g,s}\frac{\Delta Rs}{\Delta P}\right)\Delta P_g^a + \rho_g^a\Delta S_g^a + \rho_{g,s}^a Rs.\Delta S_o^a\right]$$

Numerical simulator

Unknowns

- **Let's consider a mixture of n components in a cell (3 components in black oil model)**
- **Unknowns linked to multiphase flow (for each phase):**
  - Pressure
  - Saturation
- **Unknowns linked to compositions and phase equilibrium are (for each component):**
  - Number of moles in mixture
  - Number of moles in vapor
  - Number of moles in liquid

Numerical simulator

Unknowns

SOLVING THE MATERIAL BALANCE FOR EACH COMPONENT:

OIL, WATER AND GAS

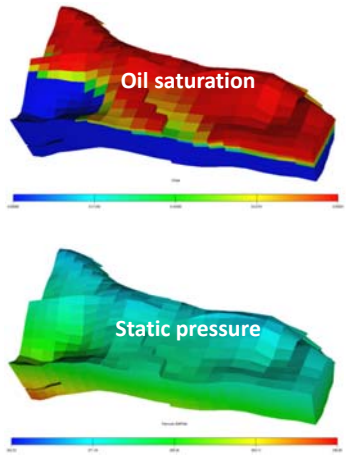
$$\sum Q_{in} - \sum Q_{out} \pm q_i = \frac{\Delta m_i}{\Delta t} \quad + \quad \begin{cases} S_o + S_g + S_w = 1 \\ P_o - P_w = Pc_{wo} \\ P_g - P_o = Pc_{go} \end{cases}$$

WE OBTAIN:

Pressures: Po, Pg, Pw
Saturations: So, Sg, Sw

i

at each time t
for each cell



Numerical simulators

Reservoir simulation model





Compositional model

- **Black oil assumption is not valid !**

- **n Componentes: C1, C2, C3, ..., Cn**
- **3 + 3n Unknowns: Mixture mass, L & V fractions, compositions (xn, yn, zn)**
- **3 + 2n Fundamental relations:**
  - Liquid and vapour fractions: $L + V = 1$
  - Mixture compositions: $L \cdot x_n + V \cdot y_n = z_n$
  - Liquid and vapour compositions: $\sum x_n = 1 \quad \& \quad \sum y_n = 1$
  - Equilibrium constants: $y_n / x_n = k_n(P,T)$

- **We will have as many flow equations as components since we have one continuity equation per component**

- **Compositional**
  - Miscible gas injection
  - CO2 injection
  - Gas condensate reservoir
  - Volatile oil reservoir
- **N components**
- **Gas/oil mass exchange (Equation of state, constants)**
- **Chemical**
  - Polymers
  - Surfactants
  - Alkaline injection
- **Multicomponents in oil and water phase**
- **Fluid/Fluid and fluid/rock interactions**

Other reservoir simulators

- **Thermal**
  - Hot fluid
  - Vapor
  - Combustion
- **Black oil or compositional thermodynamics**
- **Reaction kinetics**
- **Energy equation (temperature)**

- **Fracture**
  - Double porosity / double permeability

Numerical formulation

Partial differential equation

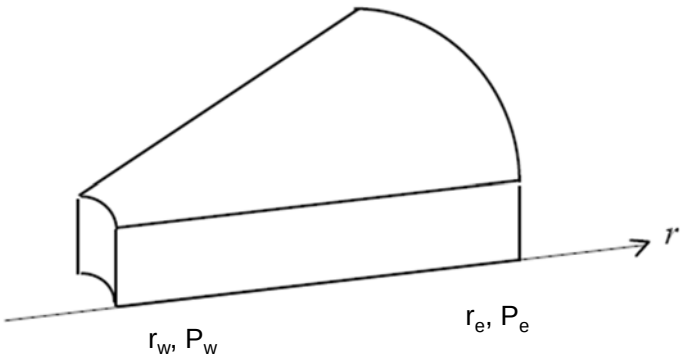
Radial flow, 1D (well test equation)

transient flow: $$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial P}{\partial r}\right)=\left(\frac{\phi\cdot\mu\cdot c}{K}\right)\frac{\partial P}{\partial t}$$

$$P=P_i+\frac{q\cdot\mu}{4\pi\cdot K\cdot h}\cdot Ei\left(-\frac{\phi\cdot\mu\cdot c\cdot r^2}{4K\cdot t}\right) \qquad Ei(-x)=-\int_x^{\infty}\frac{e^{-u}}{u}du$$

steady state flow: $$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial P}{\partial r}\right)=0$$

$$P=P_w+\frac{(P_e-P_w)}{\ln(r_e/r_w)}\cdot\ln(r/r_w)$$



Boundary conditions

- **External boundaries:**
  - No flux at the boundaries
  - Aquifer limits

- **Wells:**
  - Constant well bottom hole pressure (Dirichlet BC)
  - Constant well production rate (Neumann BC)

Well's boundary conditions

- **Rate specified in a well in block i. After computing the pressures, the actual bottom hole pressure may be computed from the well equation:**

$$Q_{o,i} = PI_i (P_{o,i} - P_{bh,i}) / (\mu_{o,i} \cdot B_{o,i})$$

- **Production wells are normally constrained by a minimum bottom hole pressure, for lifting purposes in the well. If this is reached, the well should be converted to a constant bottom hole pressure well.**

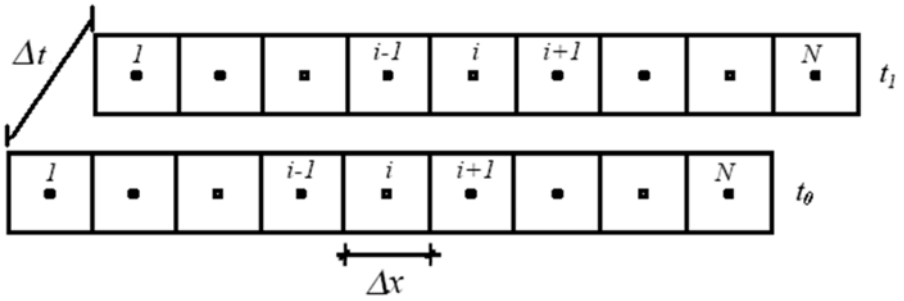
- **Constant well bottom hole pressure. Since rate terms contain unknown block pressures. At the end of each time step, actual rates are computed by these equations:**

$$q'_{o,i} = \frac{PI_i}{A \cdot \Delta x_i (\mu_{o,i} \cdot B_{o,i})} (P_{o,i} - P_{bh,i}) \qquad q'_{w,i} = \frac{PI_i}{A \cdot \Delta x_i (\mu_{w,i} \cdot B_{w,i})} (P_{w,i} - P_{bh,i})$$

and water cut is computed by: $f_{ws,i} = \frac{q'_{w,i}}{q'_{w,i} + q'_{o,i}}$

Numerical formulation

Difference equations: 1D



$$\frac{\partial^2 P}{\partial x^2} = \left(\frac{\phi \cdot \mu \cdot c}{K}\right)\frac{\partial P}{\partial t}$$

EXPLICIT FORMULATION:

$$\frac{P_{i+1}^{t} - 2P_i^{t} + P_{i-1}^{t}}{\Delta x^2} \approx \left(\frac{\phi \cdot \mu \cdot c}{K}\right) \cdot \frac{P_i^{t+\Delta t} - P_i^{t}}{\Delta t}$$

IMPLICIT FORMULATION:

$$\frac{P_{i+1}^{t+\Delta t} - 2P_i^{t+\Delta t} + P_{i-1}^{t+\Delta t}}{\Delta x^2} \approx \left(\frac{\phi \cdot \mu \cdot c}{K}\right) \cdot \frac{P_i^{t+\Delta t} - P_i^{t}}{\Delta t}$$

Numerical formulation

Stability of formulations

- **Using the von Neumann stability analysis, the stability requirement for the explicit formulation is:**

$$\Delta t \le \frac{1}{2}\left(\frac{\phi \cdot \mu \cdot c}{K}\right) \cdot \Delta x^2$$

- **Therefore, the time step size is limited by both grid block size and properties of rock and fluid.**

- **For the implicit formulation, the von Neumann analysis results in:** $\Delta t \le \infty$

- **Showing that it is unconditionally stable for all time step sizes.**

Methods of solution

- **Explicit: impractical,**
- **Fully implicit (FIM): most robust, but expensive,**
- **Partially implicit (IMPES): it is less dispersive and sometimes faster than the fully implicit method,**
- **Adaptive implicit (AIM) is generally the optimum approach: is a compromise between the fully implicit and IMPES procedures.**

In ECLIPSE simulator, the methods IMPES and AIM are used

IMPES

- **Assumptions: Transmissivities, coefficients and capillary pressures are evaluated at time t**

$$Tx^{t}_{o,i+1/2}(P_{o,i+1}-P_{o,i})+Tx^{t}_{o,i-1/2}(P_{o,i-1}-P_{o,i})-q'_{o,i}=C^{t}_{poo,i}(P_{o,i}-P^{t}_{o,i})+C^{t}_{swo,i}(S_{w,i}-S^{t}_{w,i})$$

$$Tx^{t}_{w,i+1/2}\left[(P_{o,i+1}-P_{o,i})-(Pc_{ow,i+1}-Pc_{ow,i})^{t}\right]+Tx^{t}_{w,i-1/2}\left[(P_{o,i-1}-P_{o,i})-(Pc_{ow,i-1}-Pc_{ow,i})\right]-q'_{w,i}$$
$$=C^{t}_{pow,i}(P_{o,i}-P^{t}_{o,i})+C^{t}_{sww,i}(S_{w,i}-S^{t}_{w,i})$$

- **Water and oil equations are combined in order to eliminate water saturation (Sw) as an unknown:**

$$a_i \cdot P_{o,i-1}+b_i \cdot P_{o,i}+c_i \cdot P_{o,i+1}=d_i$$

where *a, b, c* are fonctions of *T,C* and *Pcow, d* includes all the terms at time *t*

- **Using either the oil or the water equation, we solve explicitly for water saturation at t + Dt**

Convergence Problem

- **Bad convergence of Newton iterations**
  - too large Dt
  - convergence criteria too large (not enough iterations)
  - not accurate solution of linear system
  - physical reasons
- **If many step cuts**
  - change from IMPES to FIM
  - decrease the Dt increasing factor
- **Physical reasons**
  - cells with small PV
  - too large PI
  - too rapid change of rate
  - too small rate instead of Q=0
  - discontinuity in kr curves
  - very high Kv (fast segregation)
  - values outside the range in PVT tables

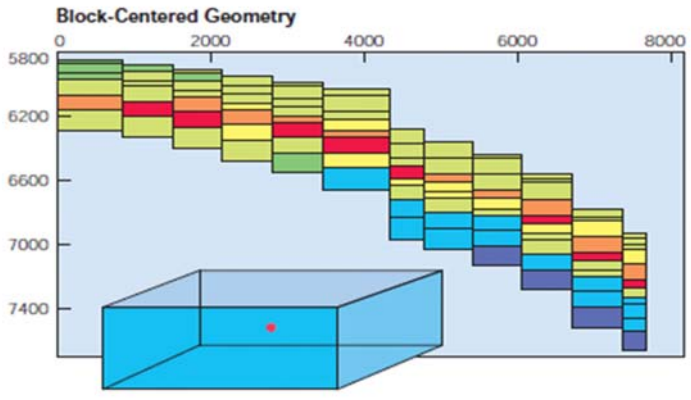
Remarks

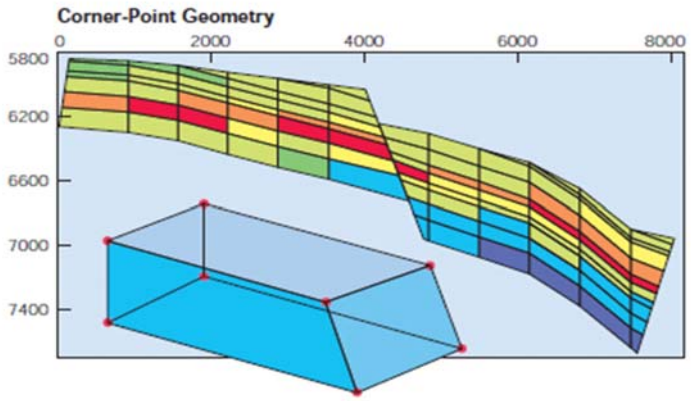
- **Many assumptions are necessary to build a reservoir model so calculations are only approximate and a good engineering judgment is required to evaluate input data.**
- **The solution of the flow equations consumes a large part of the computing effort in a simulation. As a consequence, selecting an effective equation-solving method for a particular problem is an important step in managing the cost and controlling the difficulty of a study.**

Space and time discretization

- **Space discretization:**
  - Grid definition
  - One value per grid cell for each data
  - Calculation of flow transfers between cells
- **Time discretization:**
  - Time step definition
  - Calculation of production data per time step
  - Calculation of reservoir data at the end of time step taking into account constant production data and constant reservoir data during the time step
    - Data at the beginning of the time step = explicit schema
    - Data at the end of the time step = implicit schema
- **Simulation costs increase more rapidly than the number of cells as**
  - Calculation per time steps are proportional to the number of cells
  - Time step decreases with the cell dimensions

Geometry





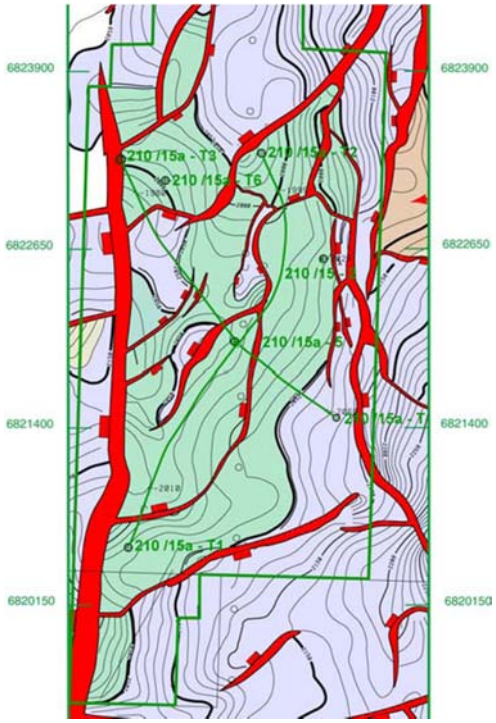
Gordon Adamson et al.,
Oilfield Review, SLB. Summer 1996

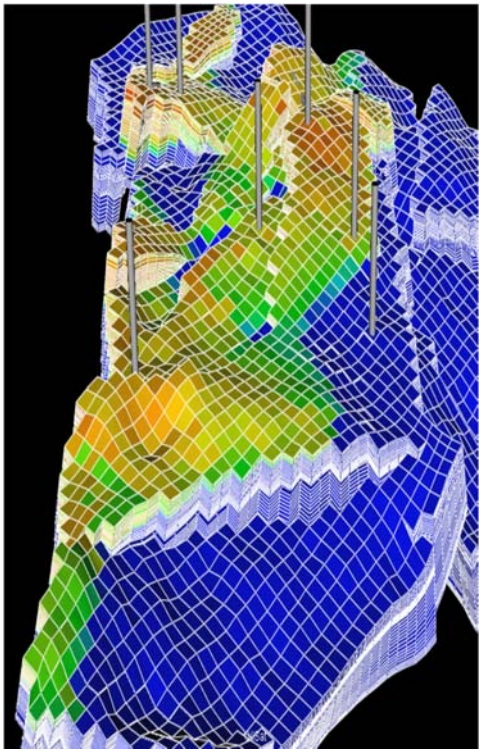
Block centered geometry features flat-topped rectangular blocks that match the mathematical models behind the simulator.

Corner point geometry modifies the rectilinear grid so that it conforms to important reservoir boundaries.

Three dimensional grids are constructed from a 2D grid by laying it on the top surface of the reservoir and projecting the grid vertically or along fault planes onto lower layers.

Spatial discretization: GRIDDING





Time discretization

- **Constraints:**

$$\Delta T_{\min} < \Delta T < \Delta T_{\max}$$
$$\Delta P = \max(\Delta P_i) < \Delta P_{\max}$$
$$\Delta S = \max(\Delta S_i) < \Delta S_{\max}$$

- **Calculations:**

$$\Delta t_{n+1} = a \cdot \Delta t_n \quad being \quad a > 1$$

$$if \quad \Delta P_{n+1} > \Delta P_{\max} \qquad \Delta t^P_{n+1} = \Delta t_n \cdot \Delta P_{n+1} / \Delta P_{\max}$$
$$if \quad \Delta S_{n+1} > \Delta S_{\max} \qquad \Delta t^S_{n+1} = \Delta t_n \cdot \Delta S_{n+1} / \Delta S_{\max}$$

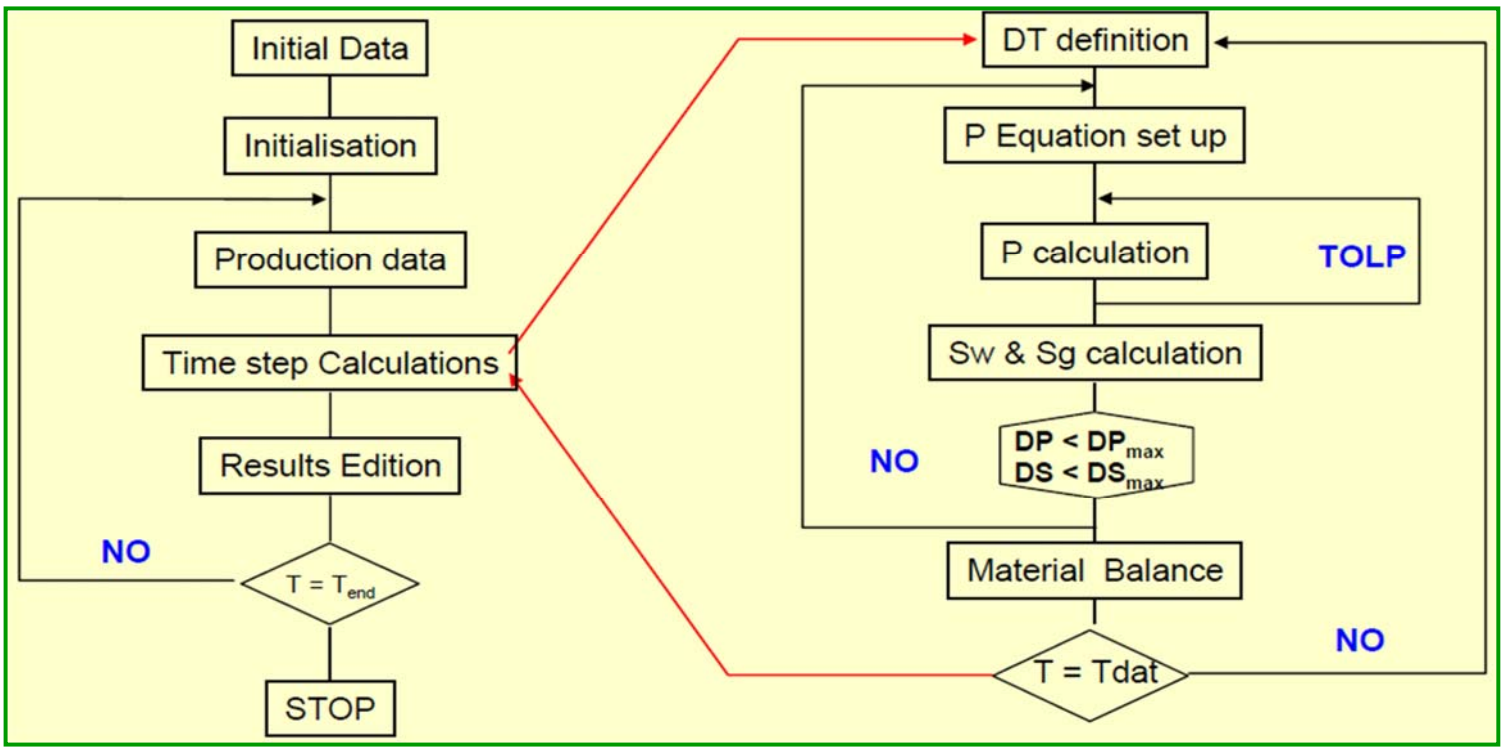
$$\Delta t_{n+1} = \min(\Delta t^P_{n+1}, \Delta t^S_{n+1})$$

$$if \quad \Delta t_{n+1} > \Delta t_{\max} \qquad \Delta t_{n+1} = \Delta t_{\max}$$
$$if \quad \Delta t_{n+1} < \Delta t_{\min} \qquad \Delta t_{n+1} = \Delta t_{\min}$$

Time discretization

- **Production parameters are assumed constant per time step**
  - Flow rates
    - Oil, gas , water, aquifer influx
  - Pressures
    - Oil, gas, water
    - Bottom hole flowing pressure
    - Well head pressure
  - Saturations
- **Flow simulator calculates for each time step and each grid block**
  - For each phase
    - 1 pressure
    - 1 saturation
    - n concentrations
  - For each component
    - 0 to 6 exchanged flow with neighbouring cells
    - 1 injection or production flow for cells connected to a well or to an aquifer

Simulator work flow



Generalities

Basic equations

- Continuity equation
- Darcy's law
- Equation of state: it will depend on the model used

Models

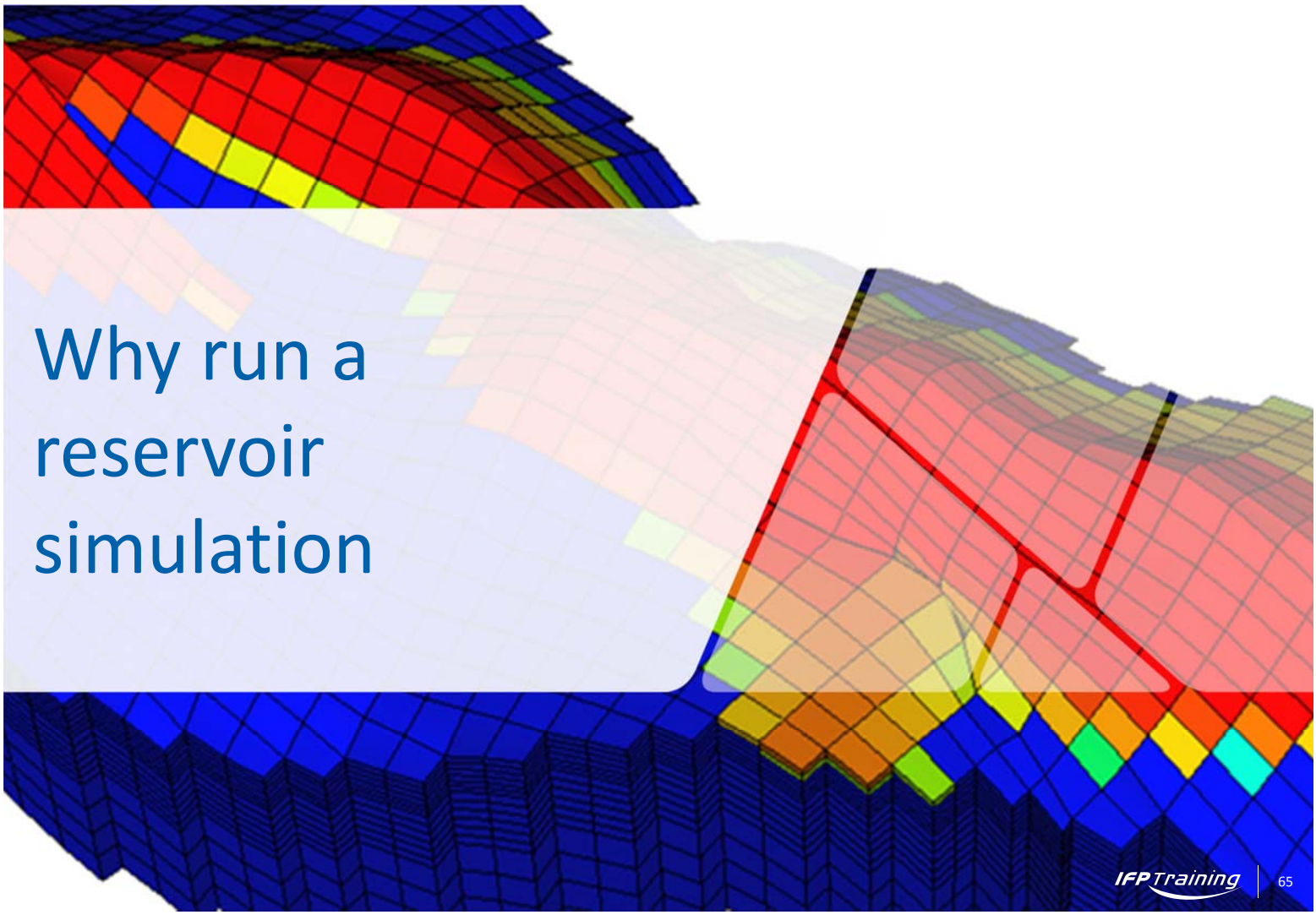
- Black oil: Produced oil and gas in standard conditions have constant compositions
- Compositional model: use of an EOS to describe the fluid (ρ)

Space discretization

- One value per grid cell for each data (ρ, K, S, P)
- Calculation of flow transfers between cells

Time discretization

- Production data are calculated at each time step



The need for reservoir simulation

- **The need for Reservoir Model comes from the fact that:**
  - It is desirable to “see, or to predict the future” of a reservoir or a field, under various production mechanisms before deciding on a development plan and investment strategy
  - It is necessary to develop techniques to simulate (assume the appearance of) reservoir behavior under likely production schemes
  - It is desirable to integrate all the available reservoir data into a model

Reservoir simulation objectives

- **In other words, reservoir simulation objectives are:**
  - To establish reliable production forecasts
  - To help decision making on development plan, appraisal drilling, infill drilling, workovers…
  - To improve reservoir description

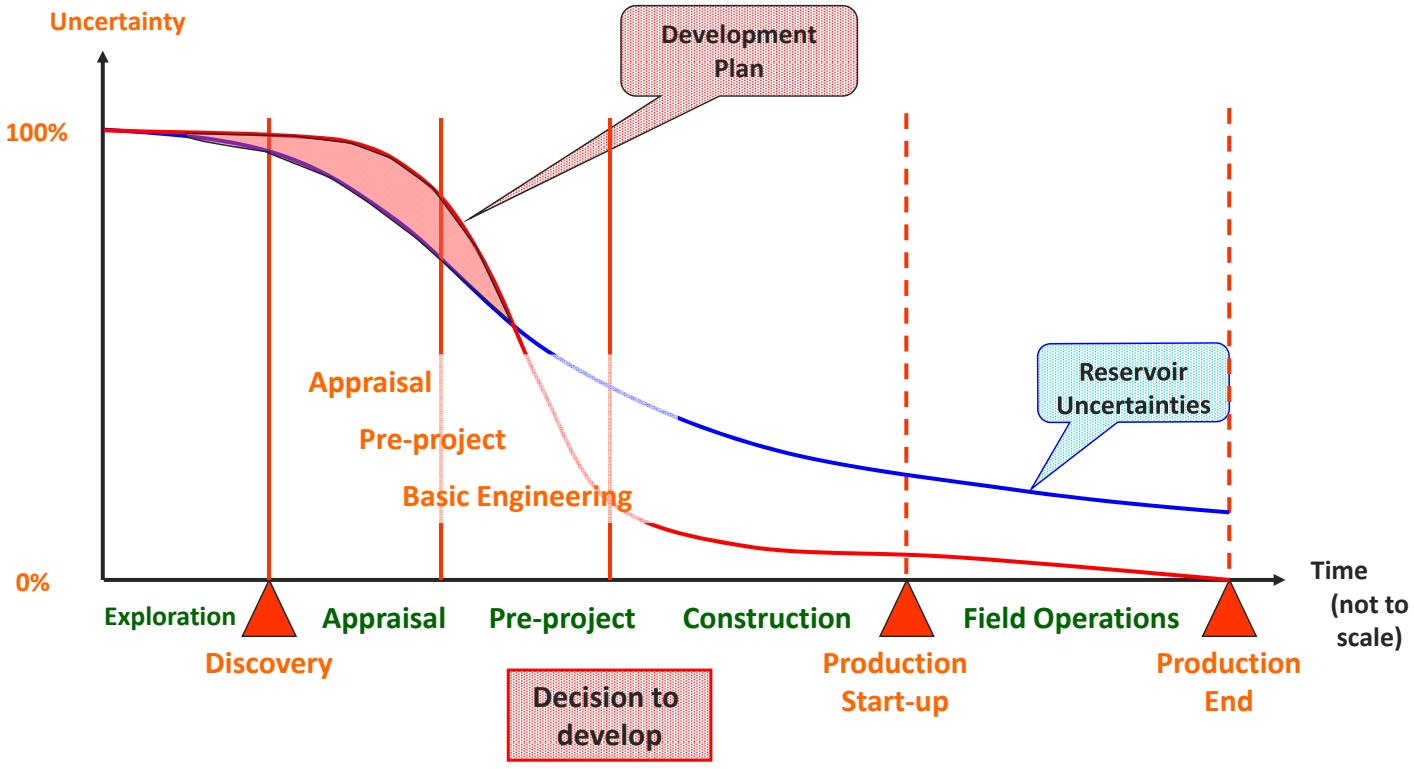
Incentives for running a flow simulation

- **Main drivers:**
  - To overcome simplifying assumptions (used in hand calculations)
  - To consider realistic problems (development plan, production history…)
  - To take into account all the available data and to better understand all the interactions between them for a given scenario
  - To perform sensitivity to unknown parameters
- **Main use:**
  - Help to decision, in particular at the end of appraisal phase and during pre-development screening
  - Optimise the production profile and the final recovery after production start-up by improving the reservoir description
  - Establish reliable production forecasts

Incentives for running a flow simulation

At all stages of a field development, dynamic reservoir simulation may help

- **Non producing reservoir**
  - To identify best production strategy (depletion, injection…)
  - To define the well number and their architecture
  - To design surface facilities
  - To evaluate risk and profitability of the development project
  - To optimize CAPEX
- **Appraisal**
  - To identify key dynamic uncertainties
  - To define appraisal needs (contacts, faults, facies variations)
- **Producing reservoir**
  - To integrate all history production data
  - To improve reservoir description
  - To optimize oil production and recovery (infill, W.O, IOR…)
- **At all stages of the development**
  - To establish reliable production forecasts
  - To evaluate (remaining) reserves



Running a flow simulation

Development project

Some examples of needs

- To define the best production strategy (natural drive, water injection, gas injection)
- To define the number, type and architecture of the wells
- To establish production profiles (oil, water, gas) that will be used by economists and architects
- To evaluate the risks associated to the project

Running a flow simulation

Development project

Study approach

- In this case, static and dynamic uncertainties are high
- One of the main objectives will be to evaluate how the different development scenarios will impact the production profile
- The need will specifically be to analyse the influence of certain reservoir parameters (permeability, fluid compressibilities, mobility ratios, heterogeneities…)
- This will necessitate a great number of prediction runs

Running a flow simulation

Producing reservoir

Some examples

- To establish reliable production forecasts: Rates, WCut, GOR, Pressures
- To optimise oil production and recovery whilst respecting all production constraints (pressures, surface facilities capacity, contract…)
- To localise remaining oil, by-passed oil
- To evaluate the need for infill drilling
- To evaluate Work-over programs to optimise oil production or reduce water production

Running a flow simulation

Producing reservoir

Approach

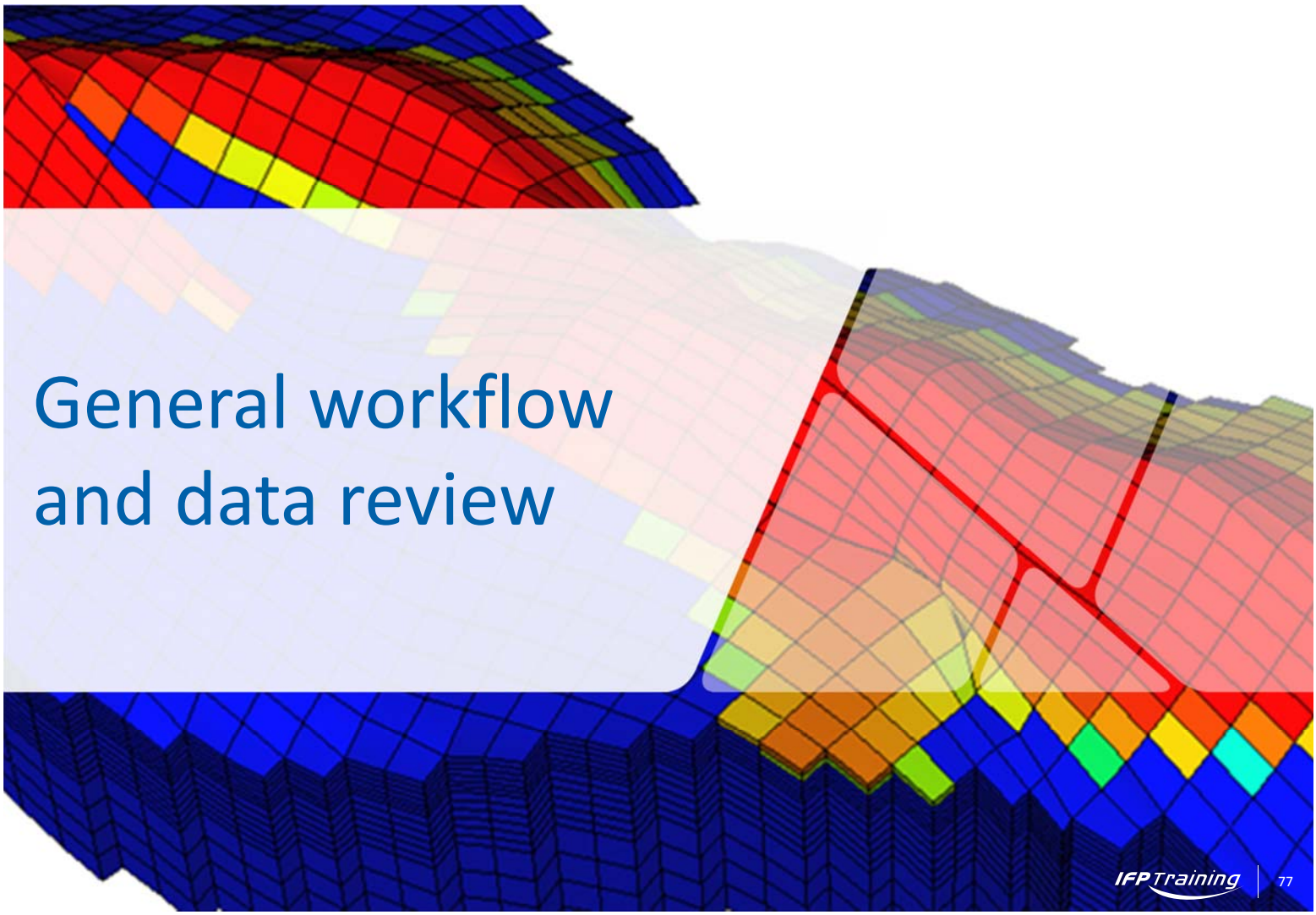
- The History Match helps to reduce the static and dynamic uncertainties
- The most influent parameters must be identified and adjustments to the reservoir description will then improve the reservoir behaviour description
- That History Match process will necessitate a great number of simulation runs

Key points to keep in mind

Why run a reservoir simulation model

- To define appraisal needs (contacts, faults, facies variations)
- To evaluate how the different development scenarios will impact the production profile
- To optimise oil production and recovery whilst respecting all production constraints (pressures, surface facilities capacity, contract…)
- To identify key dynamic uncertainties
- To assess the risks associated to the project

Help to decision, in particular at the end of appraisal phase and during pre-development screening



General workflow and data review

Reservoir Simulation Planning

- **Reservoir simulation study duration: from weeks to years**
- **Necessity to plan carefully the study to give correct results in time, before to take decisions for the field management:**
  - Problem definition
  - Data review
  - Data acquisition
  - Approach selection
  - Reservoir characterization – Build geological static model
  - Upscaling to generate dynamic reservoir simulation model
  - Computing support
  - Initialisation
  - History matching
  - Prediction
  - Reporting

Problem Definition

- **Determine present reservoir performance and associated operating issues in order to define future performance**
  - Collect information
  - Identify the problems
  - Determine the objectives

Data review

- **Data generally must be reviewed and reorganized because:**
  - They come from several sources of information
  - The review evidences inconsistencies and gaps
- **The objective of data review is to:**
  - Decide if the data quality is sufficient to conduct the study
  - Plan data acquisition for the study purpose

Data acquisition

Main Types of Data

TYPE	Geometry	Petrophysics	Fluids	Wells	Production
Description	Shape Thickness Dimensions Faults Contacts	Porosity Permeability Compress. Pc's Kr's Swi Sorw	Bo, µo… Bg, µg… Bw, µw…	Coordinates Completion PI	Qo = f(t) Qg = f(t) Qw = f(t) Separat. Cond.
Origin	Seismics Geology Well tests	Logs, cores Laboratory Tests	Laboratory Abacus	Well report Tests	Field

Study approach

- **What is the most suitable model to answer the problems:**
  - Model dimensions (1D, 2D, 3D)
  - PVT type (Black oil, compositional)
  - Special physical options (double media, thermal, chemical…)
- **Factors influencing the study approach are:**
  - Availability of simulators and computing environment
  - Time, money and manpower

Model design

Model design is influenced by:

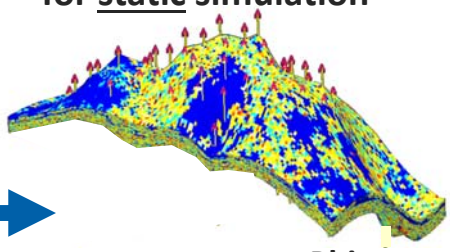
- Type of process to model
- Complexity in fluids mechanisms
- Objectives of the study
- Quality of data
- Needed level of details
- Budget

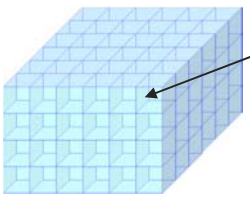
Grid Parameters

REALITY



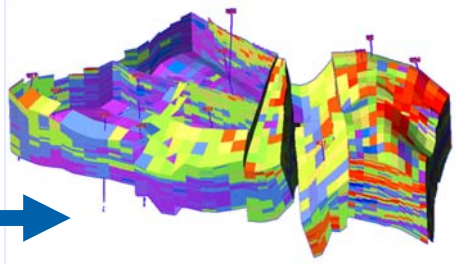
GEOLOGICAL MODEL
(OR GEOMODEL)
for static simulation

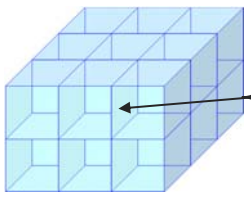




- A quantitative synthesis
- One model for each parameter
- Used to:
  - Understand spatial hydrocarbon distribution
  - Accumulation computation

RESERVOIR MODEL
for dynamic simulation





Not to predict the reservoir

But to anticipate the dynamic behavior

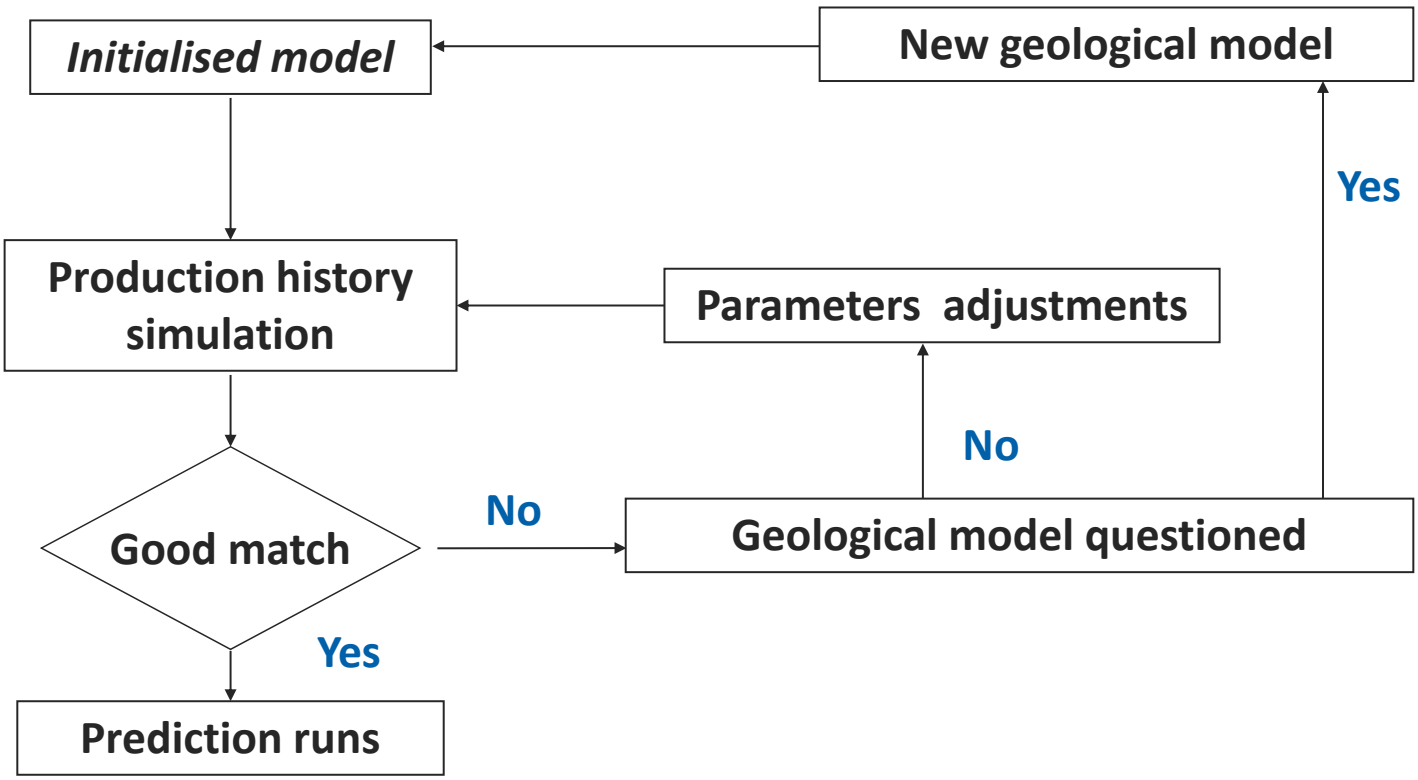
History match

- **In general two phases are distinguished:**
- **Initialisation**
  - Model data checking
  - Calculation of fluids in place
- **History match**
  - Run with imposed rate
  - Calculation of P, Fw, GOR
  - Comparison with field measurements
  - Adjustment of parameters
  - Modification of input data
  - New run

History match

- **Objective:**
  - Reproduce with the model the measured evolutions of pressure, BSW and GOR by well, by zone or for the entire field
- **Difficulties:**
  - Uncertainties on fault and flow barriers network; parameters are dependent
- **Rule of thumb:**
  - Predictions are reliable on a period twice the production period

History match – Principle scheme



Predictions

- **Predictions can be run once history match has been completed. The objective is to predict the future performance of the reservoir under different exploitation scenarios**
- **Results of major interest are:**
  - Future oil performance
  - Future water-cut and GOR evolution
  - Pressure evolution
  - Fluid contact evolution
  - Work-over requirements
  - Drilling requirements
  - Surface facilities requirements
  - Estimate the recovery factor
- **The analysis of results must be done by comparison of the different cases**

Reporting

- **Give always a clear and concise report with:**
  - Statement of the objectives of the study
  - Description of the model
  - Presentation of the results
  - Conclusions and recommendations
- **In most of reservoir studies give both:**
  - Managerial report (read by many people)
  - Detailed report (read by only a few people, but essential for future update)
- **Don’t forget to save data, results and reports.**

Key points to keep in mind



- **Simulation models are only tools**
- **An integrated reservoir study requires a multidisciplinary approach that integrates complementary techniques**
- **Use material balance and simple tools to check your data**
- **Watch out during data analysis and input**
- **Check the geologic validity of the data**
- **Check result validity**
- **A good model is one that provides an accurate flow representation, with:**
  - An adapted 3D grid
  - A realistic set of petrophysical parameters
  - A successful upscaling
- **The model is reliable at time t, but at t + Δt?**

Be very patient!

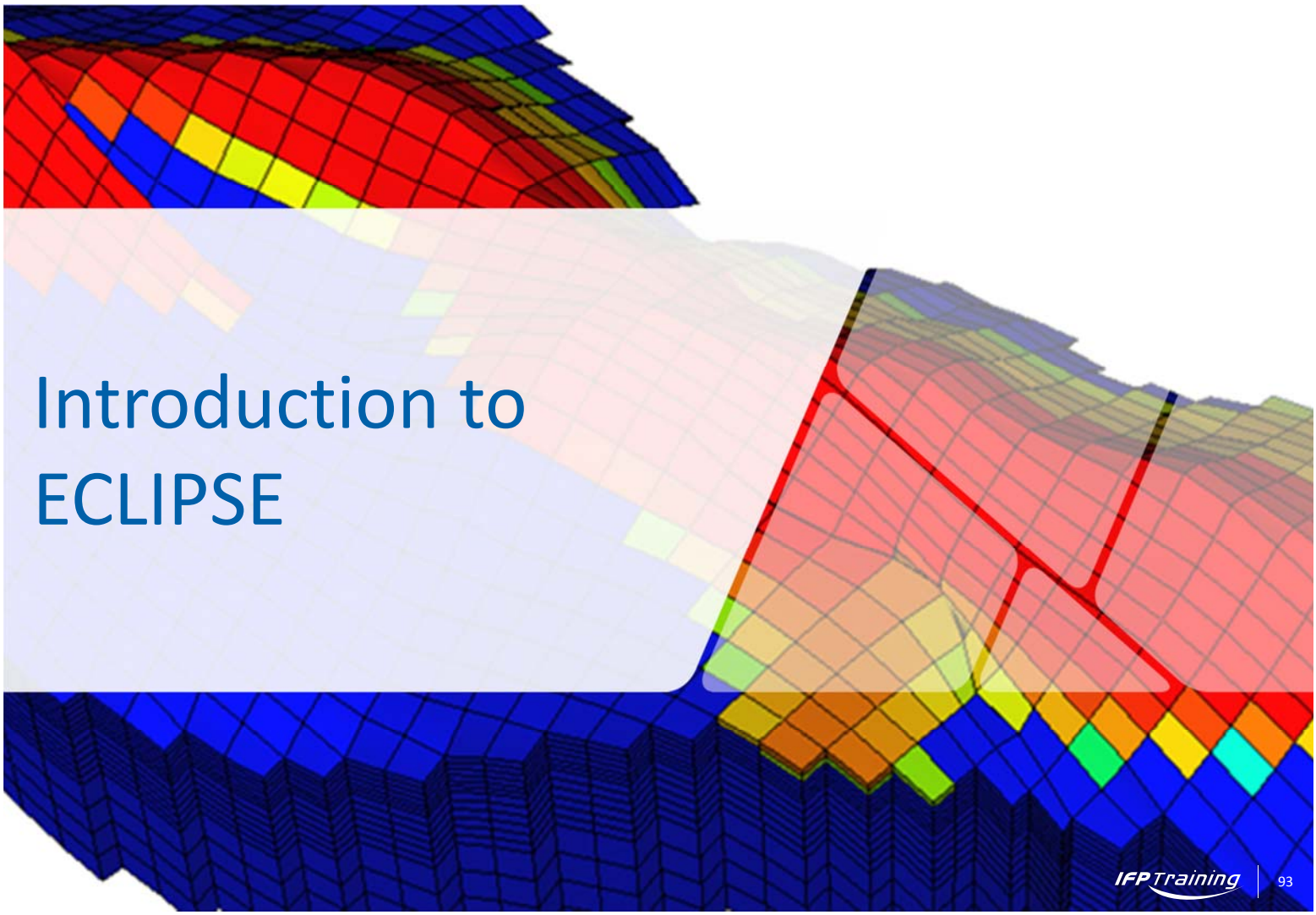


Reservoir simulation workshop
Simulator presentation

IFP Training

Simulator presentation

- Introduction to ECLIPSE 93
- ECLIPSE input data and reservoir simulation 99
- ECLIPSE keywords in well definition 117
- ECLIPSE output
  Visualization of results 127



Introduction to ECLIPSE

What is ECLIPSE?

- **The ECLIPSE simulator suite consists of two separate simulators:**
  - ECLIPSE 100: Black-oil simulator
  - ECLIPSE 300: Compositional simulator
- **Both programs are written in FORTRAN77 and operate on any computer with a FORTRAN77 compiler**
- **ECLIPSE 100 is a fully-implicit, three phase, three dimensional, general purpose black-oil simulator with gas condensate options**
  - Oil and Gas phases are represented by one component
  - Composition of oil and gas components are assumed to be constant with pressure and time
  - The properties of those components can however change with Pressure and Temperature

ECLIPSE

- **ECLIPSE 100:**
  - 3-D, 3-phase fully implicit Black Oil
  - Advanced local grid refinement, Polymer flooding
  - Pipeline network and wellbore friction model
  - Gas field operations and solvent model

- **ECLIPSE 300:**
  - N component compositional and black oil model
  - Cube Equation of State
  - K-value or Black Oil treatment for PVT
  - Full coupling with network and geochemical models

How does ECLIPSE work?

- **ECLIPSE is a batch program, running with a single input data file**

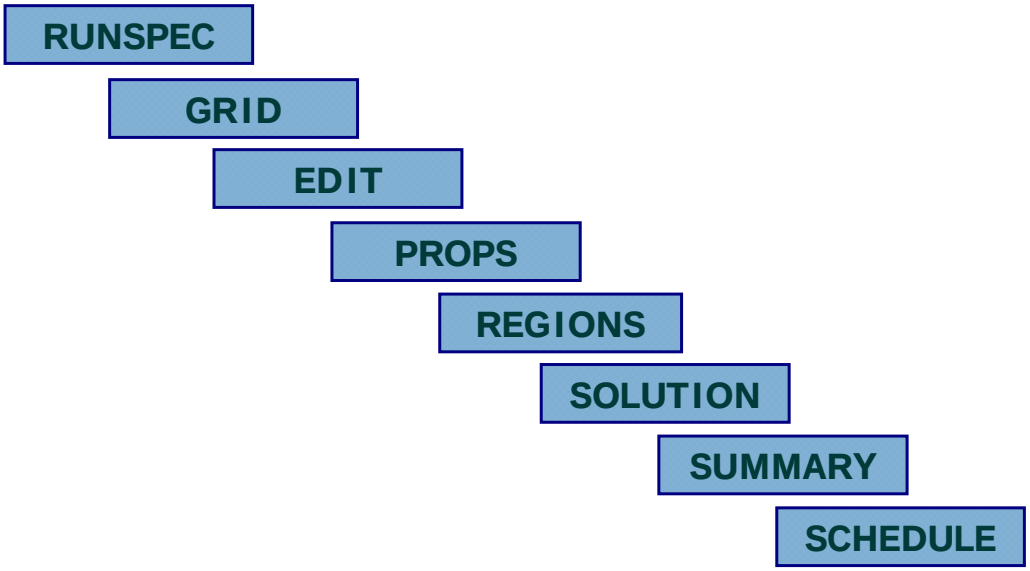
- **This Data file contains a complete description of the model:**
  - Structure, reservoir description, fluid and rock properties, initial conditions, wells with their flow rates, surface facilities and constraints

- **The input file is structured by a serie of KEYWORDS and comments**

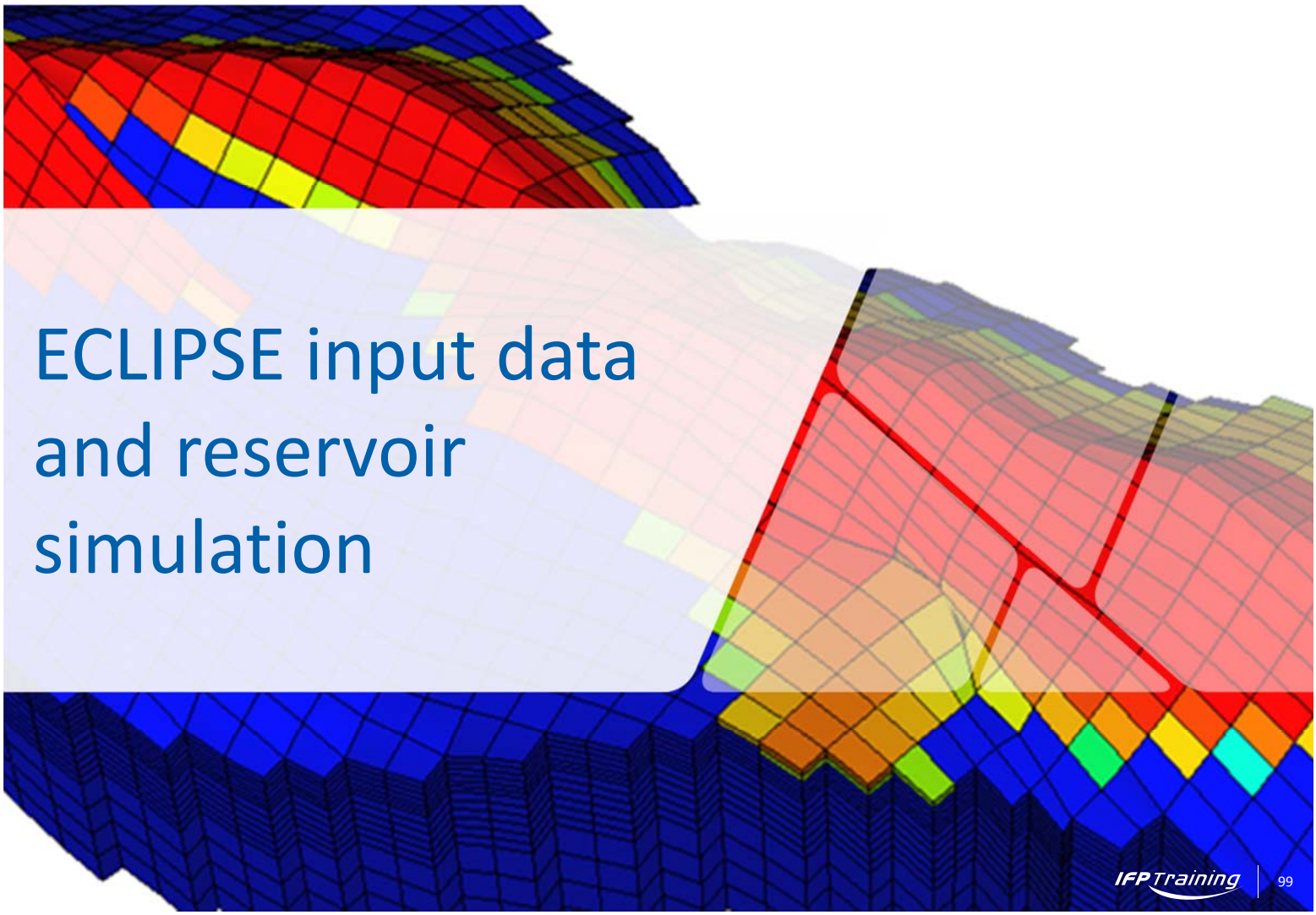
- **This file is typically divided into 8 sections**

Section-header keywords

- Eclipse Model: the input data file is an ASCII text file organized into 8 sections



- The sections must be specified in the shown order.
- It is recommended that the body of sections which are not frequently changed be held in separate files which are included in the data using the INCLUDE keyword.
- A data record has to be ended with a slash [/]



ECLIPSE input data and reservoir simulation

Section-header keywords

RUNSPEC Status: REQUIRED

- Title, problem dimensions, switches, phases present, components etc.

GRID Status: REQUIRED

- The GRID section determines the basic geometry of the simulation grid and various rock properties (porosity, absolute permeability, net-to-gross ratios) in each grid cell.

EDIT Status: OPTIONAL

- Modifications to calculated pore volumes, grid block centre depths and transmissivities.

PROPS Status: REQUIRED

- Tables of properties of reservoir rock and fluids as functions of fluid pressures, saturations and compositions. Contains the equation of state description in compositional runs.

Section-header keywords

REGIONS Status: OPTIONAL

- Splits computational grid into regions for calculation of:
  - PVT properties (fluid densities and viscosities): PVTNUM
  - saturation properties (relative permeability and capillary pressure): SATNUM
  - initial conditions, (equilibrium pressures and saturations): EQLNUM
  - fluids in place (fluid in place and inter-region flows): FIPNUM
- If this section is omitted, all grid blocks are put in region 1.

SOLUTION Status: REQUIRED

- Specification of initial conditions in reservoir may be:
  - calculated using specified fluid contact depths to give potential equilibrium
  - read from a restart file set up by an earlier run
  - specified by the user for every grid block (not recommended for general use)
- This section contains sufficient data to define the initial state (pressure, saturations, compositions) of every grid block in the reservoir.

Section-header keywords

SUMMARY Status: REQUIRED

- Specification of data to be written to the Summary file after each time step. Necessary if certain types of graphical output (for example water-cut as a function of time) are to be generated after the run has finished. If this section is omitted no Summary files are created.

SCHEDULE Status: REQUIRED

- Specifies the operations to be simulated (production and injection controls and constraints) and the times at which output reports are required. Vertical flow performance curves and simulator tuning parameters may also be specified in the SCHEDULE section.

Keywords in sections

RUNSPEC section

TITLE	title
DIMENS	number of blocks in X,Y,Z directions
OIL, WATER, GAS, VAPOIL, DISGAS	the active phases present
FIELD/METRIC/LAB	unit convention
WELLDIMS	well and group dimensions
UNIFIN	indicates that input files are unified
UNIFOUT	indicates that output files are unified
START	start date of the simulation
NOSIM	data checking only, with no simulation

Keywords in sections

GRID section

TOPS	depths of top faces of grid blocks for the current box; data is taken from Structure map, and geological model from PETREL
DX, DY, DZ	X,Y,Z-direction grid block sizes for the current box; data is taken from Isopac map, and geological model from PETREL
PERMX, PERMY, PERMZ	X,Y,Z-direction permeabilities for the current box; data is taken from Isopac map, and geological model from PETREL
PORO	grid block porosities for the current box; data is taken from Isopac map, and geological model from PETREL

Grid and properties distribution from PETREL model

Keywords in sections

PROPS section

SWFN	water relative permeability and capillary pressure as functions of S_w	saturation tables from special core analysis
SOF3	oil relative permeability as a function of S_o in three phase system	
SGFN	gas relative permeability and capillary pressure as functions of S_g	
PVTO	FVF and viscosity of live oil as functions of pressure and R_s	reservoir fluid properties from PVT analysis
PVDG	FVF and viscosity of wet gas as functions of pressure and R_v	
PVTW	FVF, compressibility and viscosity of water	
DENSITY	stock tank fluid densities	
ROCK	rock compressibility	

Keywords in sections

PROPS section

SWFN	**Saturation tables from SCAL**
SOF3	
SGFN	
PVTO	**PVT file might be generated in PVTi using a PVT report**
PVDG	
PVTW	
DENSITY	
ROCK	

Keywords in sections

REGIONS section

FIPNUM	fluid-in-place regions
SATNUM	saturation table for drainage process regions
IMBNUM	saturation table for imbibition process regions
EQLNUM	equilibration regions
PVTNUM	PVT data regions

Rock type distribution from PETREL model

Keywords in sections

SOLUTION section

EQUIL	fluid contact depths and other equilibration parameters
RESTART	name of the restart file
RPTSOL	report switches for SOLUTION data

Model initialization:
Data from RFT, logs and MBAL

Keywords in sections

SUMMARY section

Fxxx	Field quantities
Gxxx	Group quantities
Rxxx	Region quantities
Wxxx	Well quantities
Cxxx	Connection quantities
Bxxx	Block quantities

Keywords in sections

SUMMARY section

FOPT	WOPT	Field or Well Oil Production Total
FOPR	WOPR	Field or Well Oil Production Rate
FGOR	WGOR	Field or Well Gas-Oil Ratio
FWCT	WWCT	Field or Well Water Cut
FWIR	WWIR	Field or Well Water Injection Rate
FWIT	WWIT	Field or Well Water Injection Total
FOIP		Field Oil in Place
FOE		Field Oil Efficiency
FPR		Field Pressure
FORFR		Field Fraction Total Oil Produced by Rock Compaction
FORFF		Field Fraction Total Oil Produced by Free Gas Influx
FORFW	FORFG	Field Fraction Total Oil Produced by Water or Gas Influx
FORFE	FORFS	Field Fraction Total Oil Produced by Oil Expansion or Gas Expansion

Keywords in sections

SUMMARY section

WBHP	WTHP	Well Bottom Hole Pressure or Tubing Head Pressure
WBP5	WBP9	Well 5 or 9-Point Pressure Average
WPI5	WPI9	Well Productivity Index Based on Value of WBP5 or WBP9
WOPRH	WOPTH	Well Oil Production Rate or Oil Production Total History
WWCTH	WGORH	Well Water Cut or GOR History
WMCTL		Well Mode Control
TCPU		Time of CPU Usage

Keywords in sections

SCHEDULE section

TUNING	time step and convergence controls
WELSPECS	introduces a new well: name, wellhead position, bottom hole reference depth, etc
COMPDAT	specifies the position and properties of one or more well completions
WCONPROD	control data for production wells
WCONINJE	control data for injection wells
WCONHIST	observed rates for history matching wells
DATE	advances simulator to specified report dates

Wells and production data

Repeat counts

- In the data following a keyword, asterisks may be used to signify repeat counts. A data quantity can be repeated a required number of times by preceding it with the required number and an asterisk.
- There must be no intervening blank spaces next to the asterisk on either side.
- For example, the two following cases are equivalent:

```
RPTSCHED
   0 0 0 0 0 0 0 0 0 0
   0 2 0 0 2    /
```

```
RPTSCHED
   11*0 2 2*0 2    /
```

Comments

- Any lines beginning with the two characters '--' are treated as comments, and will be ignored by ECLIPSE.

```
-- VARIATION OF INITIAL RS WITH DEPTH
--
--    DEPTH    RS
RSVD
       8200  1.270
       8500  1.270  /
```

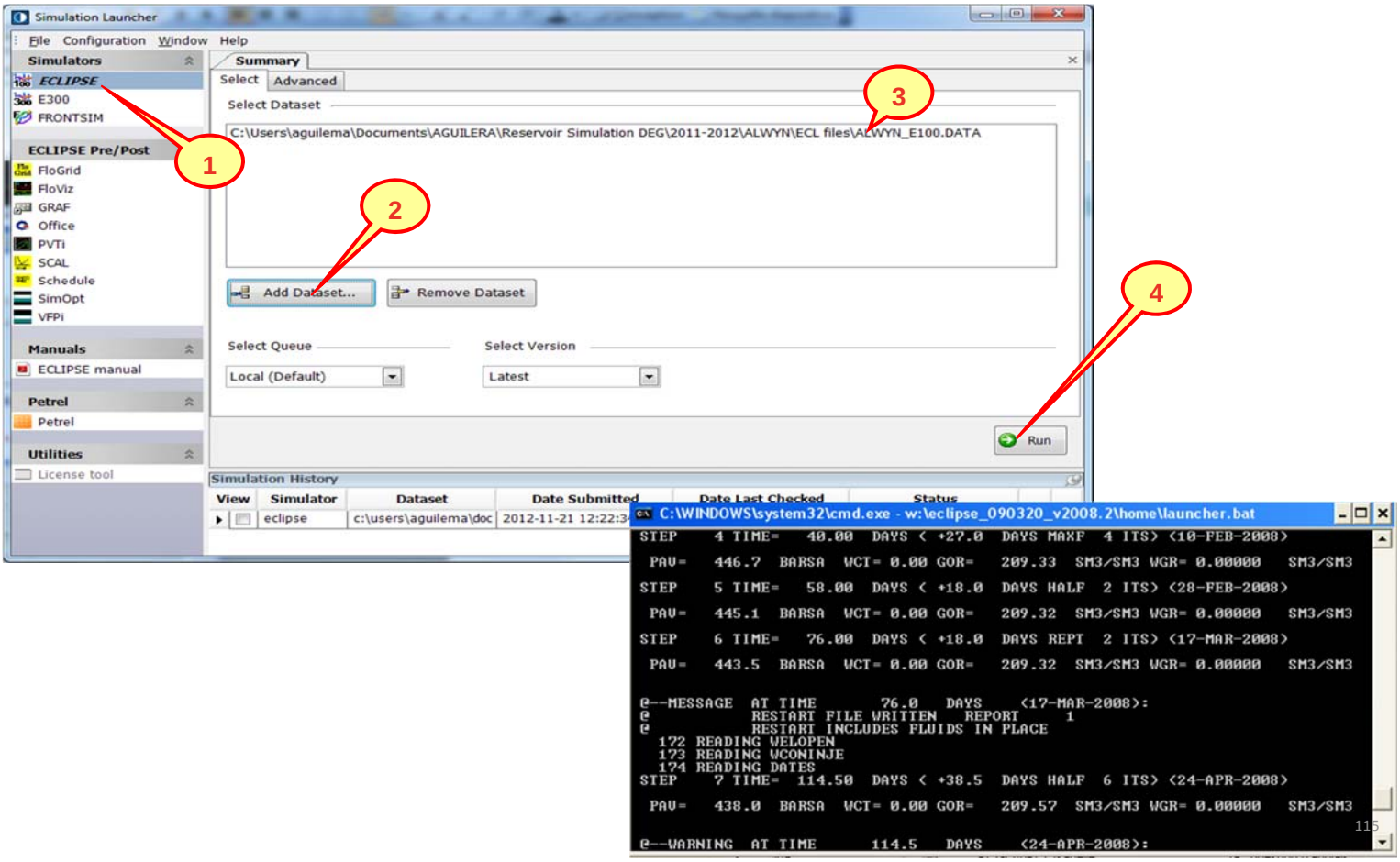

Default values

- Certain items of data can be defaulted to a built-in default value. The keyword description will indicate when defaults can be applied. There are two ways of setting quantities to their default values:

1. by ending a data record prematurely with a slash (/) the quantities remaining unspecified will be set to their default values.
2. selected quantities positioned before the slash can be defaulted by entering n* where n is the number of consecutive quantities to be defaulted. There must be no blank space between the number and the asterisk. If there is only one item at a time to be defaulted, then 1* must be entered (an asterisk by itself is not sufficient).

```
WCONPROD
  'PRODUCER' 'OPEN' 'ORAT' 20000  4*  1000 /
/
```

Running simulation: launch ECLIPSE

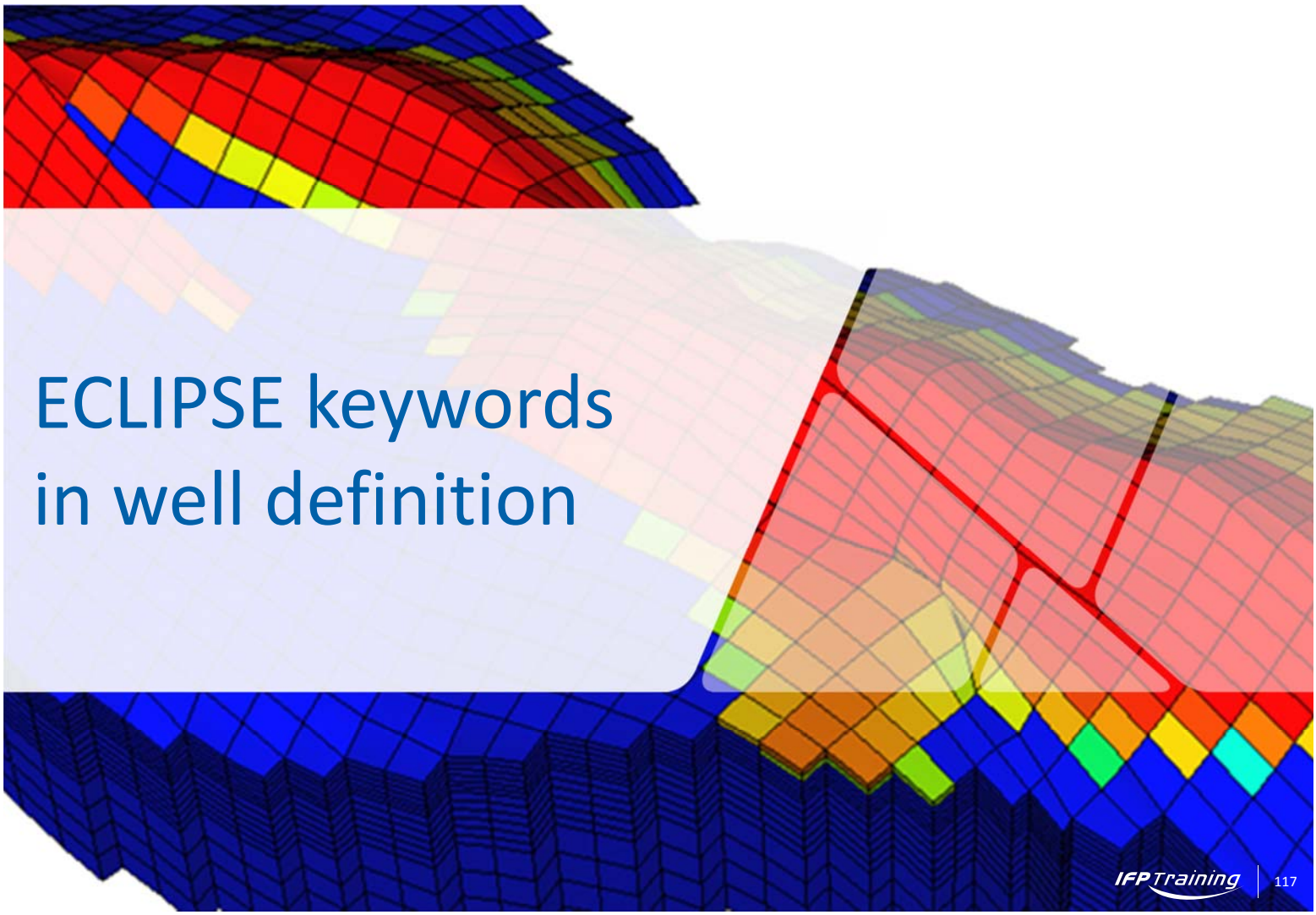


Running simulation

- **While the model is running, status reports will be written to the file FILENAME.PRT.**

- **When the run is finished, your folder contains the following files:**

  - ✓ FILENAME.DBG
  - ✓ FILENAME.EGRID
  - ✓ FILENAME.PRT
  - ✓ FILENAME.INIT
  - ✓ FILENAME.SMSPEC
  - ✓ FILENAME.UNRST
  - ✓ FILENAME.UNSMRY
  - ✓ FILENAME.RSSPEC
  - ✓ FILENAME.INSPEC



ECLIPSE keywords in well definition

Eclipse keywords

Well definition

WELSPECS: General specification data for wells

```
WELSPECS
--name    group      i      j      BHP_ref_dep   phase
   'P1'   'PROD'    20     7          2500          'OIL'       /
/
```

- Well P1 belongs to group PROD
- Well head is at i=20, j=7
- BHP reference depth of 2500 m. Defaults to depth of top-most connection
- OIL is the preferred phase (used only for PI output)
- Other items can usually be defaulted

Eclipse keywords

Well completion

```
COMPDAT
--name   i    j   k1  k2  status        CF     diam    kh    skin       direction
   'P1'   20   7   3   3   'OPEN'  1*  23.47   0.15     /
   'P1'   20   7   4   4   'OPEN'  1*   6.14   0.15     /
   'P1'   20   6   4   4   'OPEN'  1*   8.25   0.15     /
   'P1'   20   6   5   5   'OPEN'  1*  94.70   0.15   520.3  2    1*      Z   /
/
```

- P1 is a deviated well crossing columns (20,7) and (20,6) completed in layers 3 to 5
- The CF have been calculated in SCHEDULE application and input in item 8
  - the well bore diameter must be given
  - kh, skin and direction of penetration may be given for information as in the last line above

Eclipse keywords

Production Well Controls

WCONPROD : Control data for production wells

```
WCONPROD
--name  status   control   Qos   Qws   Qgs  Qls  Qfond   BHP     THP    VFP
   'P1'  'OPEN'  'ORAT'   500   300  1000  1*    1*      50       15      1  /
/
```

- Well P1 has a target oil rate of 500, subject to:
  - Maximum water rate of 300.
  - Maximum gas rate of 1000.
  - Minimum BHP of 50.
  - Minimum THP of 15
- VFP table 1 applies to this well.

Well Economic Constraints

WECON : Economic limit data for production wells

```
WECON
--name     Qomin    Qgmin    maxWCT    maxGOR    maxWGR    action
   'P1'      50       1*        0.8        1*        1*       'CON'  /
/
```

- **Well P1 is subject to:**
  - A minimum oil rate of 50 sbpd: connections of P1 will be closed if this rate cannot be met.
  - A maximum water cut of 0.8: the connections with the highest WCT will be closed

Injection Well Controls

WCONINJE : Control data for injection wells

```
WCONINJE
--name    phase    status    control    Qs    Qres    BHPlim    THPlim    VFP
   'I1'    'WATER'   'OPEN'    THP    1000    1*        300         40         2    /
/
```

- Well I1 injects water at THP = 400 bar, subject to:
  - Maximum rate of 1000 sm^3/d.
  - Maximum BHP of 300 bar.
- VFP table 2 applies to this well.

Eclipse keywords

Other well controls

WELOPEN: Opens and closes both wells and completions.

```
WELOPEN
--name     action
   ‘P1’     'OPEN' /   opens P1, does not alter completions
   'P2'     'STOP'  /   closes P2 but allows cross-flow
   ‘P3’     'OPEN'    0   0   0  /   opens all completions in P3
   ‘P4’     'SHUT'    0   0   2  /    closes all completions in P4 in layer 2
   ‘P5’     'SHUT'    0   0   0   4   6  /   closes completion 4, 5 and 6 of P5
/
```

- Opening a well and its completions requires 2 lines.
- Possible well status: OPEN, SHUT, STOP or AUTO
- Possible completion status: OPEN, SHUT or AUTO

Eclipse keywords

Other well controls

WEFAC: Defines well activity or efficiency factor (downtime).

```
WEFAC
--name     efficiency
   ‘P1’          0.95     /
/
```

- The well P1 is 95% of the time on production, for example to model shut-down of 1 day each month.
- Well rates and pressures are calculated using full rate, group rates and all cumulatives account for the efficiency factor.

Timestep management and convergence

TUNING: Sets simulator control parameters.

Record 1: Time stepping controls
Record 2: Time truncation and convergence controls
Record 3: Control of Newton and linear iterations

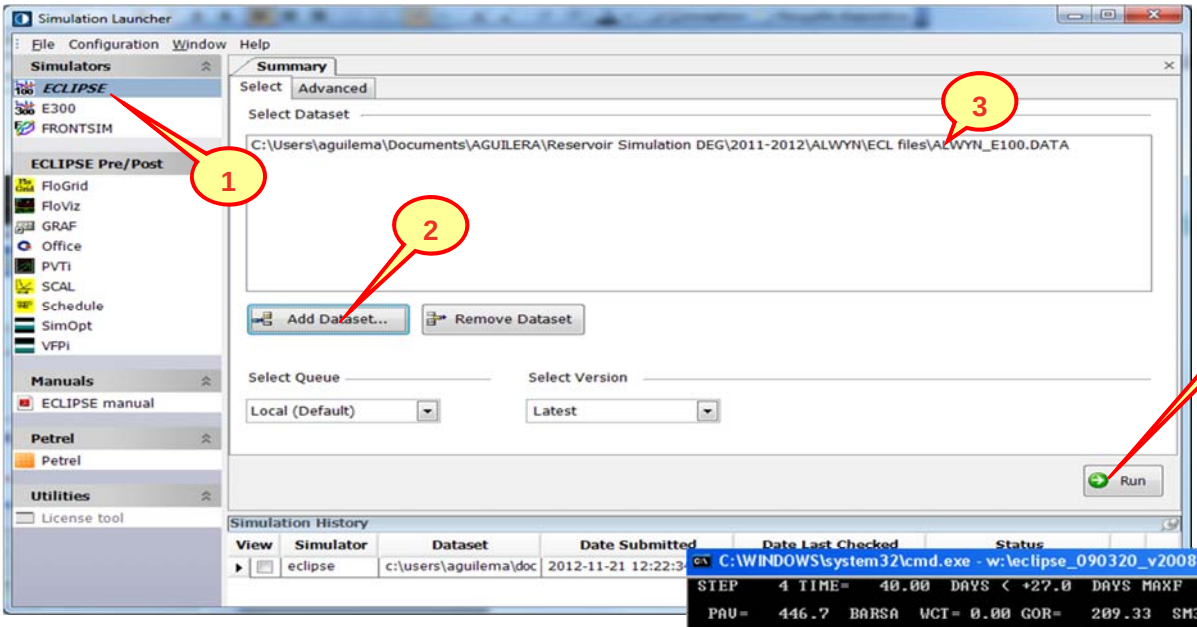
```
TUNING
 1   50   0.1  /
/
1*   1*    25   /
```

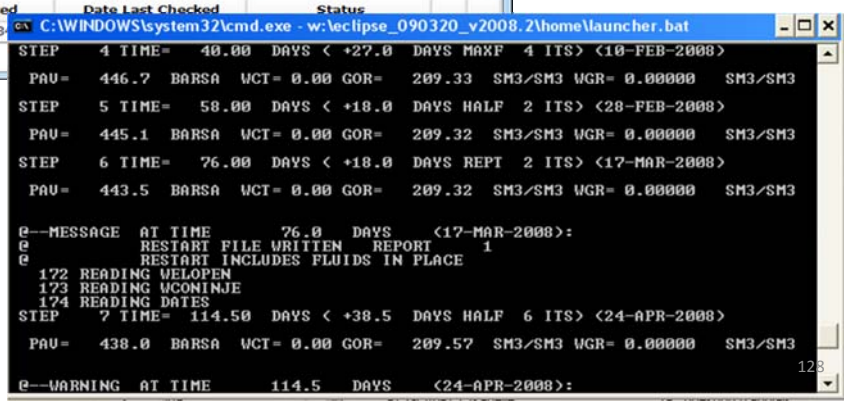
Timestep = 1 day, upper limit of next timestep = 50 days, and minimum length of all timesteps

Minimun & maximum number of Newton iteration defaulted, and maximum number of linear iteration = 25

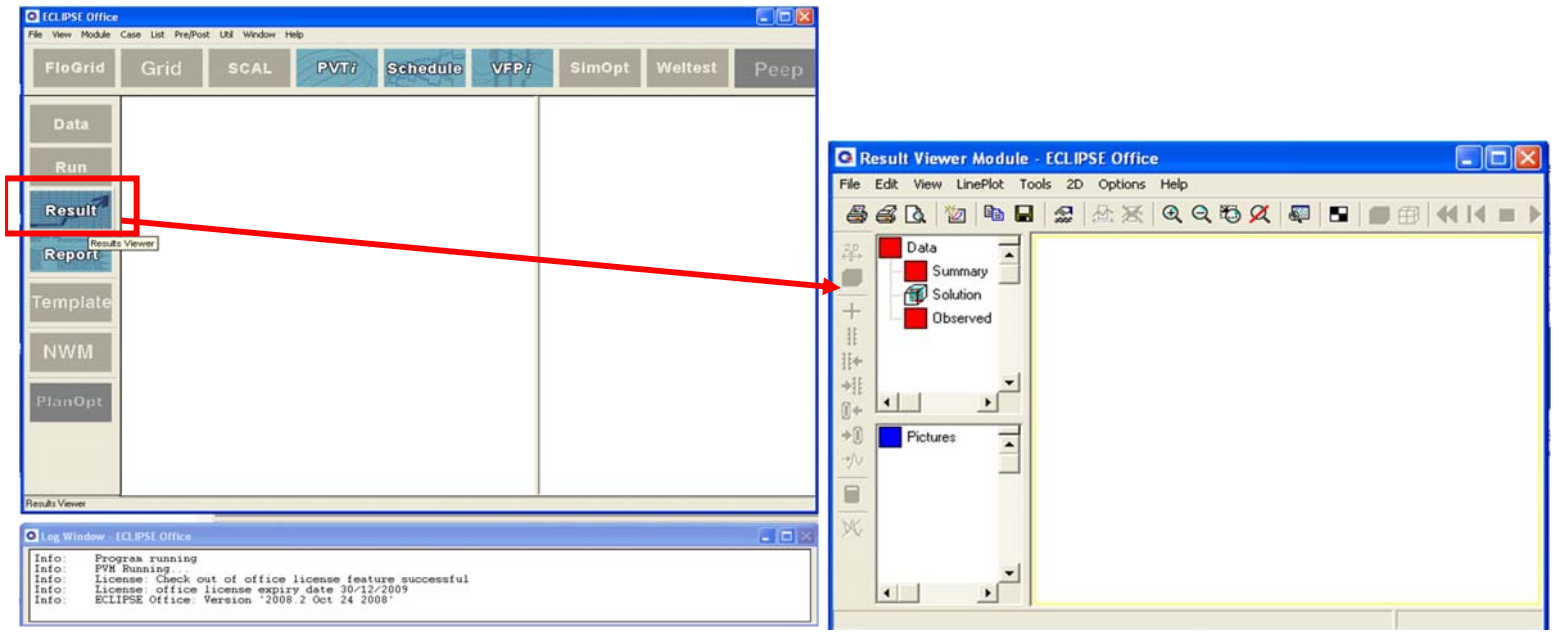
ECLIPSE output Visualization of results

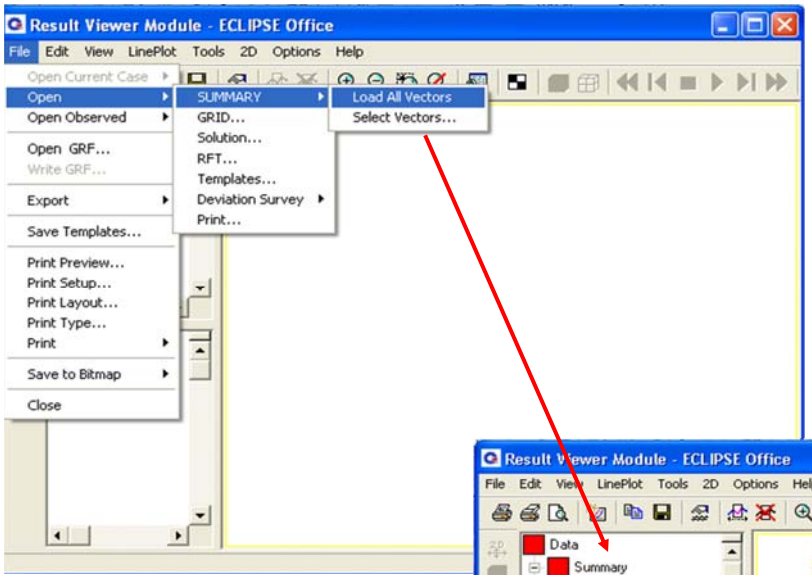
Running simulation: launch ECLIPSE



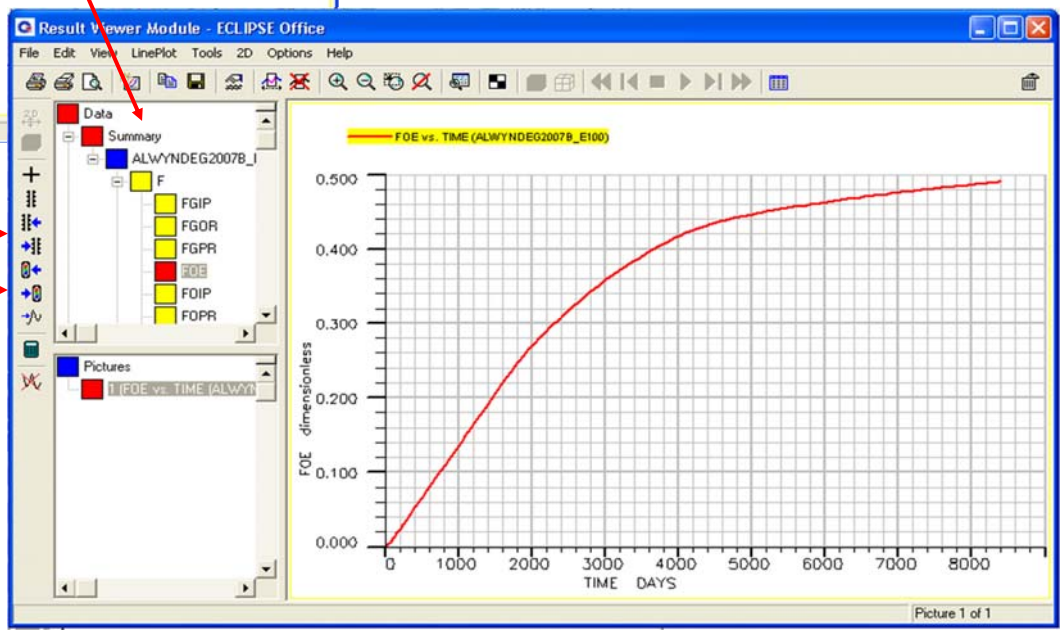


Output files



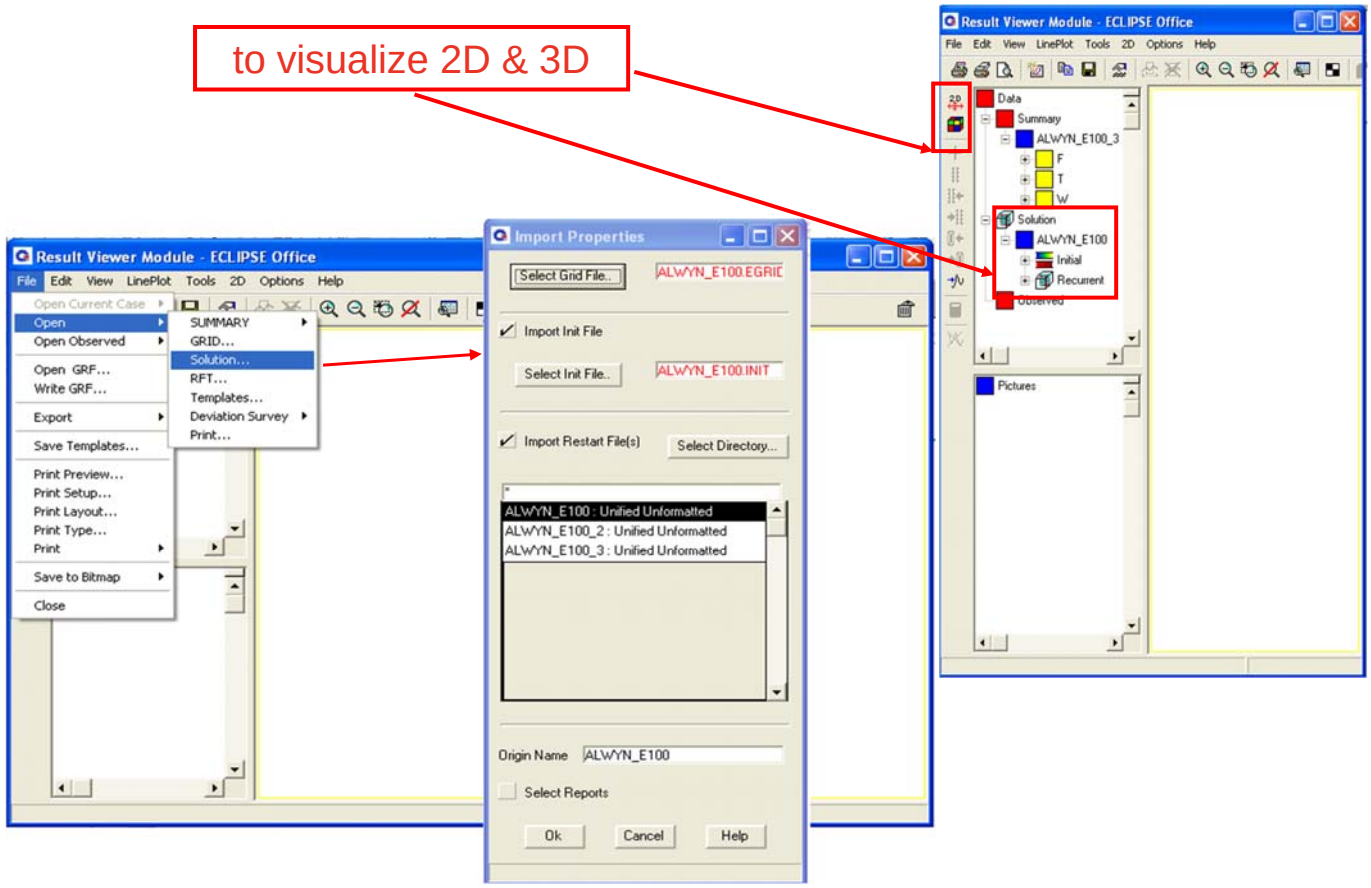


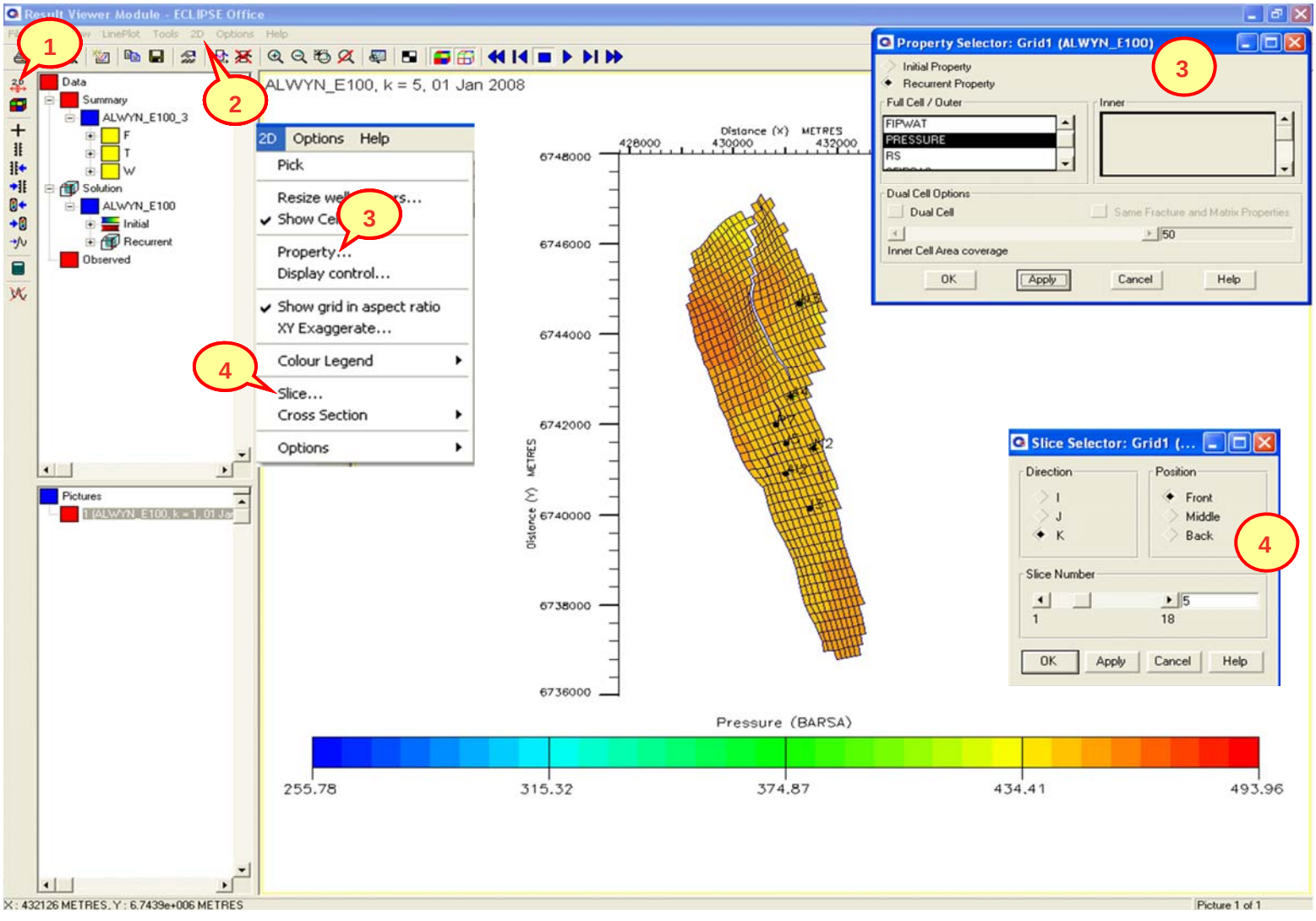
to visualize curves



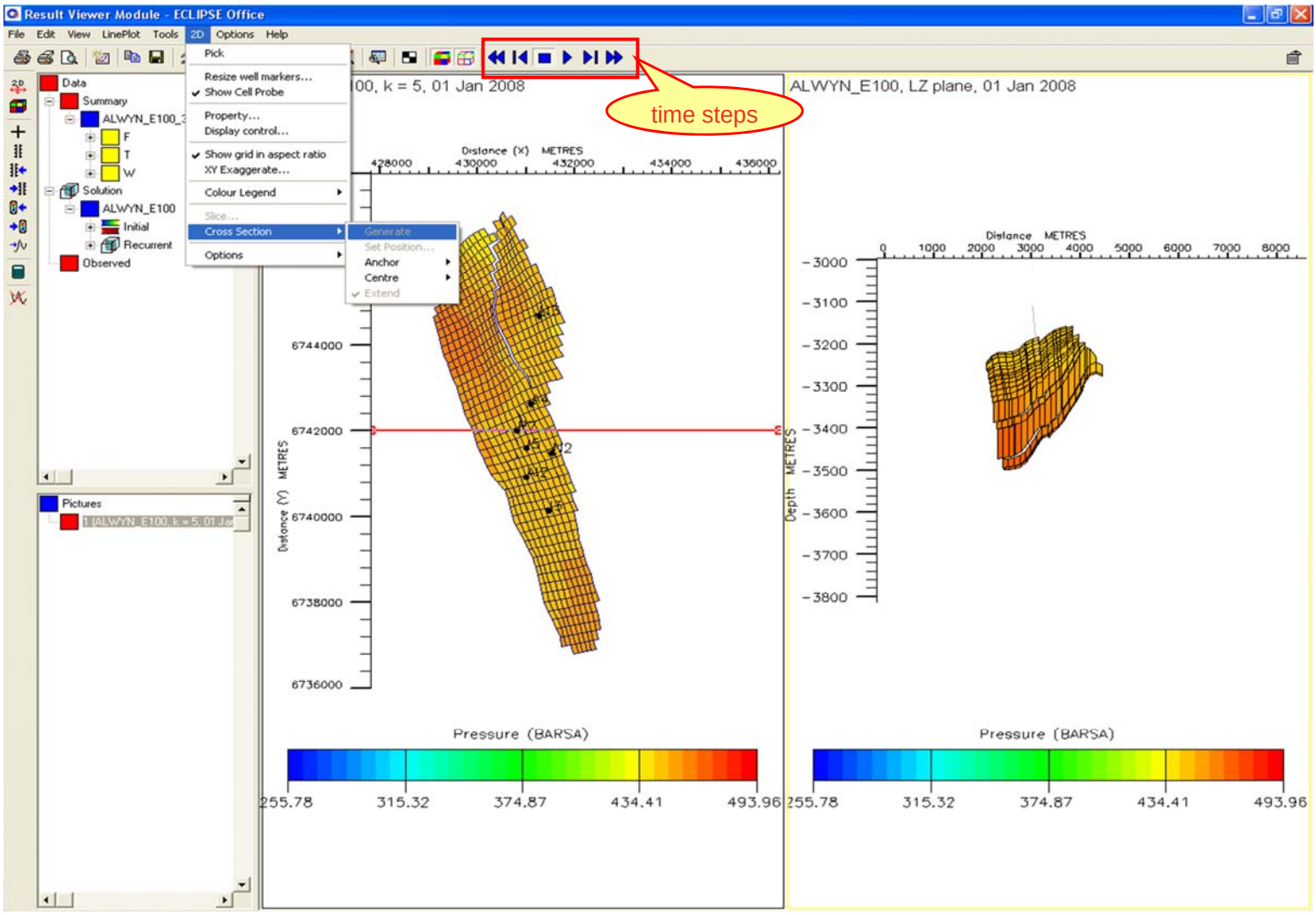
template well by well

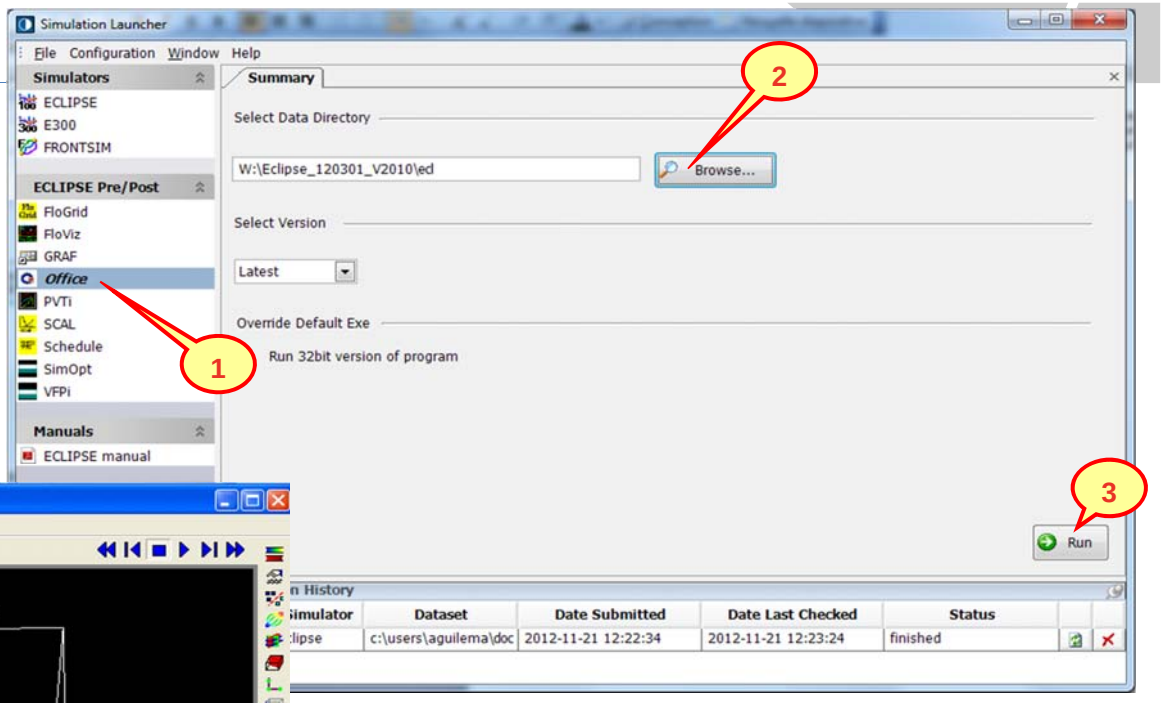
previous or next picture

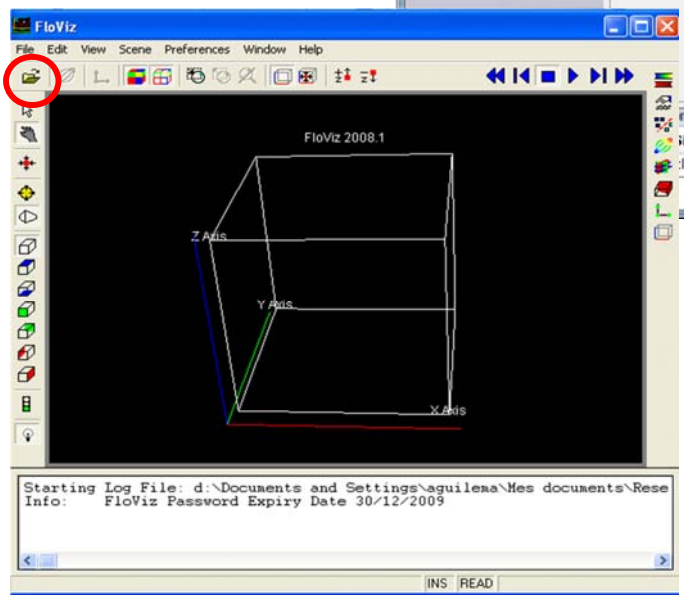

to visualize 2D & 3D
Result Viewer Module - ECLIPSE Office
File Edit View LinePlot Tools 2D Options Help
Open Current Case
Open
Open Observed
Open GRF...
Write GRF...
Export
Save Templates...
Print Preview...
Print Setup...
Print Layout...
Print Type...
Print
Save to Bitmap
Close
SUMMARY
GRID...
Solution...
RFT...
Templates...
Deviation Survey
Print...
Import Properties
Select Grid File..
ALWYN_E100.EGRID
Import Init File
Select Init File..
ALWYN_E100.INIT
Import Restart File(s)
Select Directory...
ALWYN_E100 : Unified Unformatted
ALWYN_E100_2 : Unified Unformatted
ALWYN_E100_3 : Unified Unformatted
Origin Name
ALWYN_E100
Select Reports
Ok
Cancel
Help
Data
Summary
ALWYN_E100_3
F
T
W
Solution
ALWYN_E100
Initial
Recurrent
Observed
Pictures


Result Viewer Module - ECLIPSE Office
1
2
3
4
ALWYN_E100, k = 5, 01 Jan 2008
2D Options Help
Pick
Resize wel...rs...
Show Ce...
Property...
Display control...
Show grid in aspect ratio
XY Exaggerate...
Colour Legend
Slice...
Cross Section
Options
Property Selector: Grid1 (ALWYN_E100)
Initial Property
Recurrent Property
Full Cell / Outer
FIPWAT
PRESSURE
RS
Inner
Dual Cell Options
Dual Cell
Same Fracture and Matrix Properties
Inner Cell Area coverage
OK
Apply
Cancel
Help
Slice Selector: Grid1 (...
Direction
I
J
K
Position
Front
Middle
Back
Slice Number
1
18
Distance (X) METRES
428000
430000
432000
6748000
6746000
6744000
6742000
6740000
6738000
6736000
Distance (Y) METRES
Pressure (BARSA)
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315.32
374.87
434.41
493.96
X: 432126 METRES, Y: 6.7439e+006 METRES
Picture 1 of 1

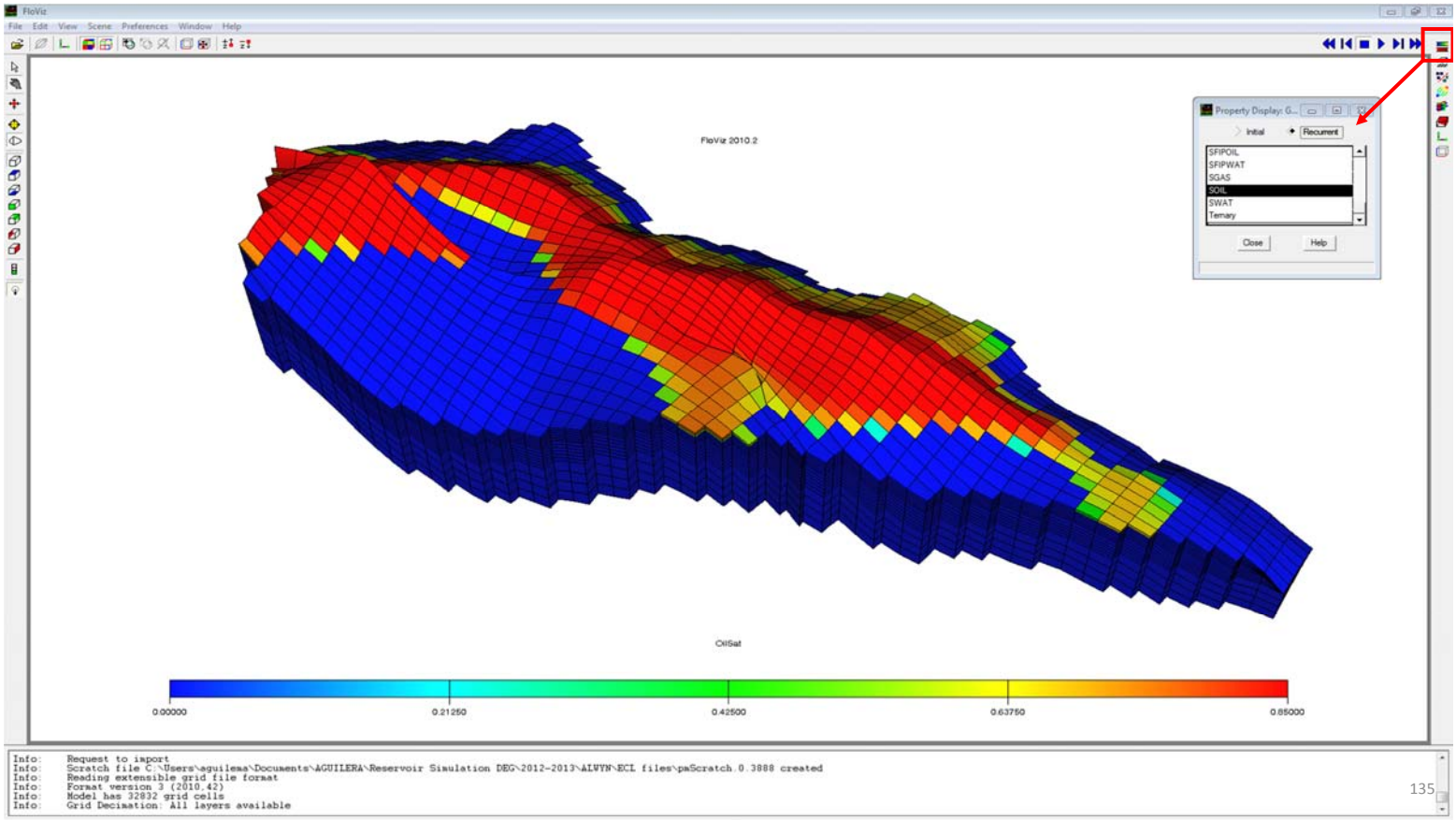
Output files



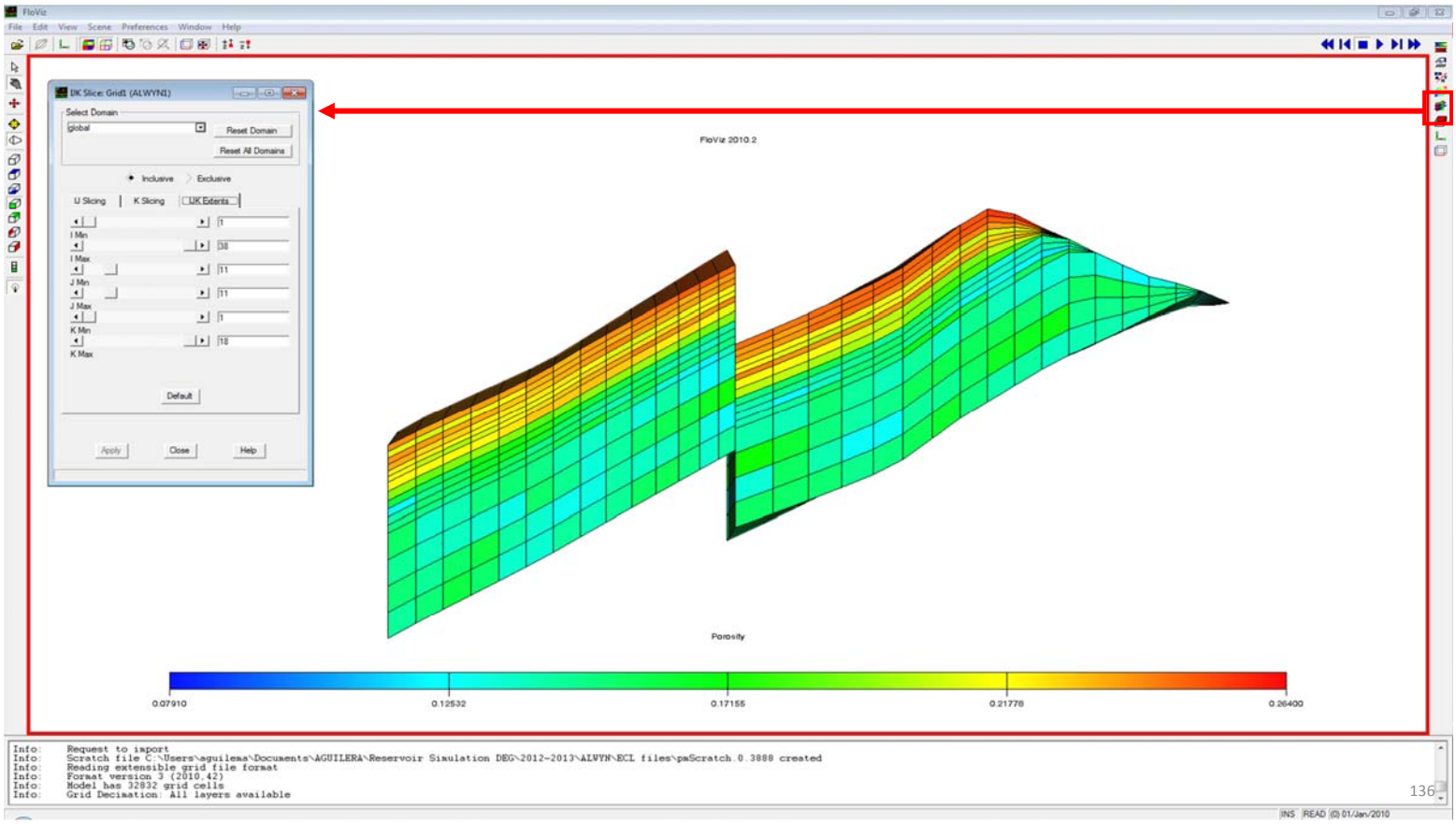




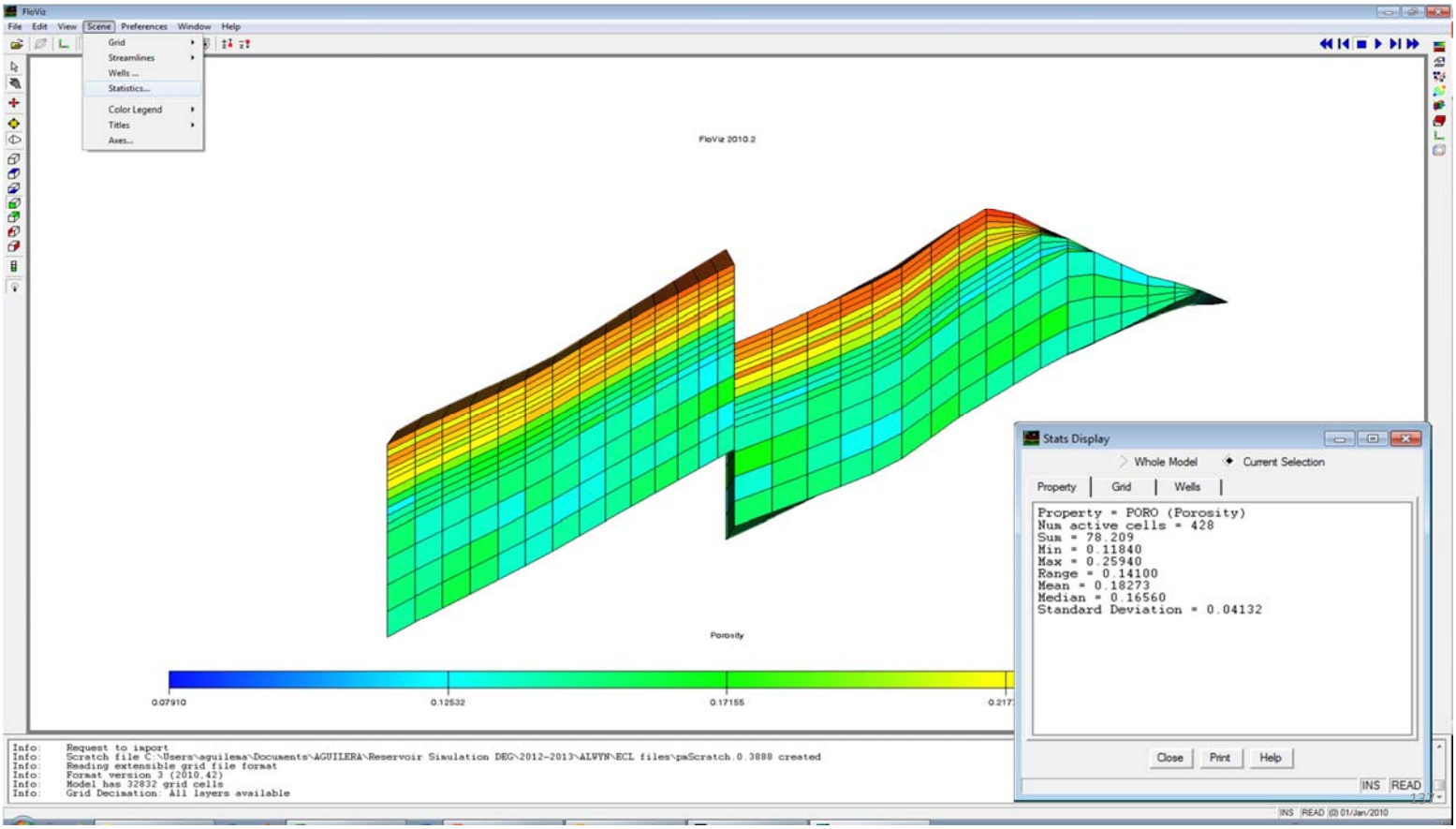
3D visualization



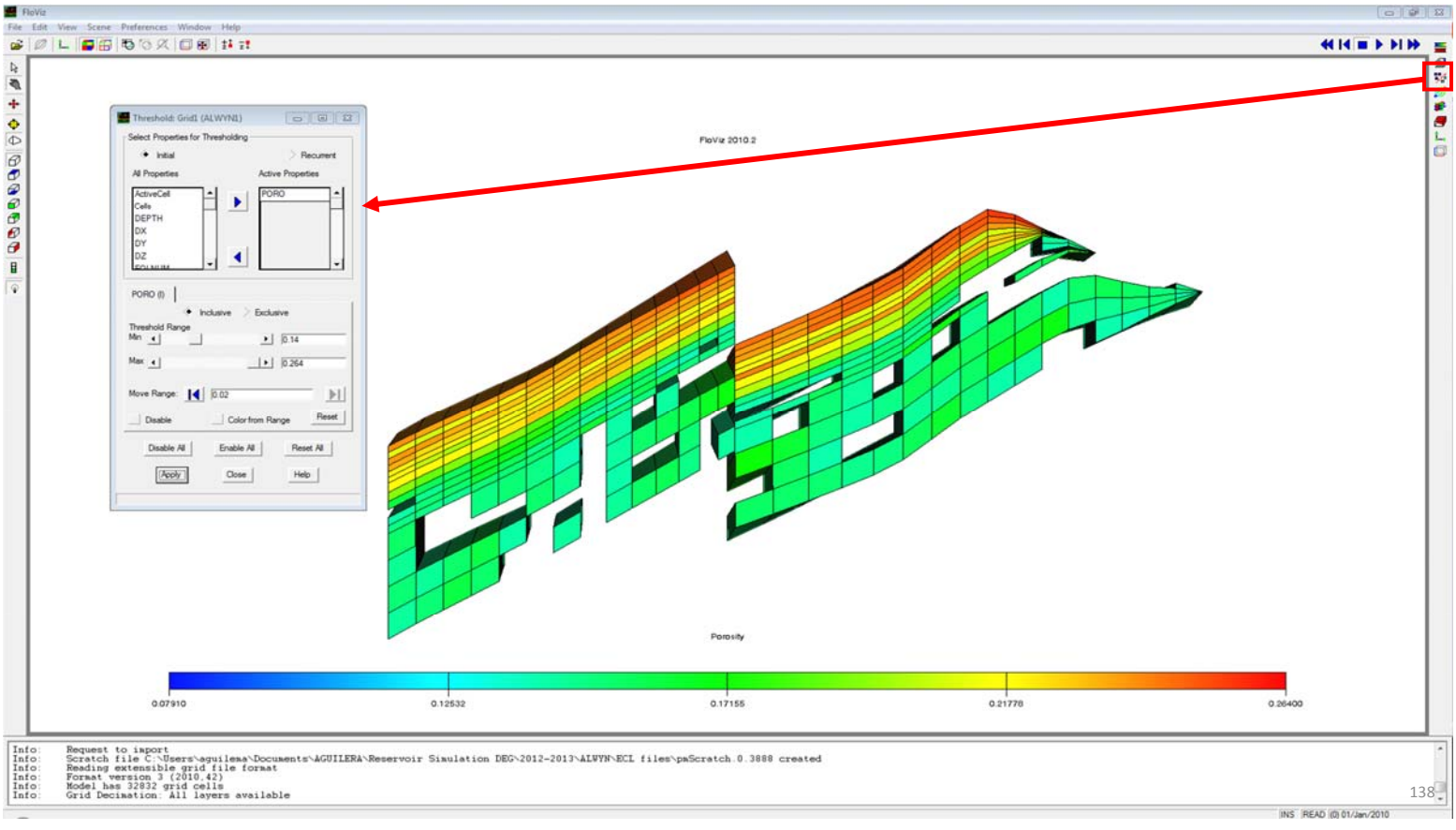
3D visualization



3D visualization



3D visualization





Dynamic reservoir simulation
Data review: gridding

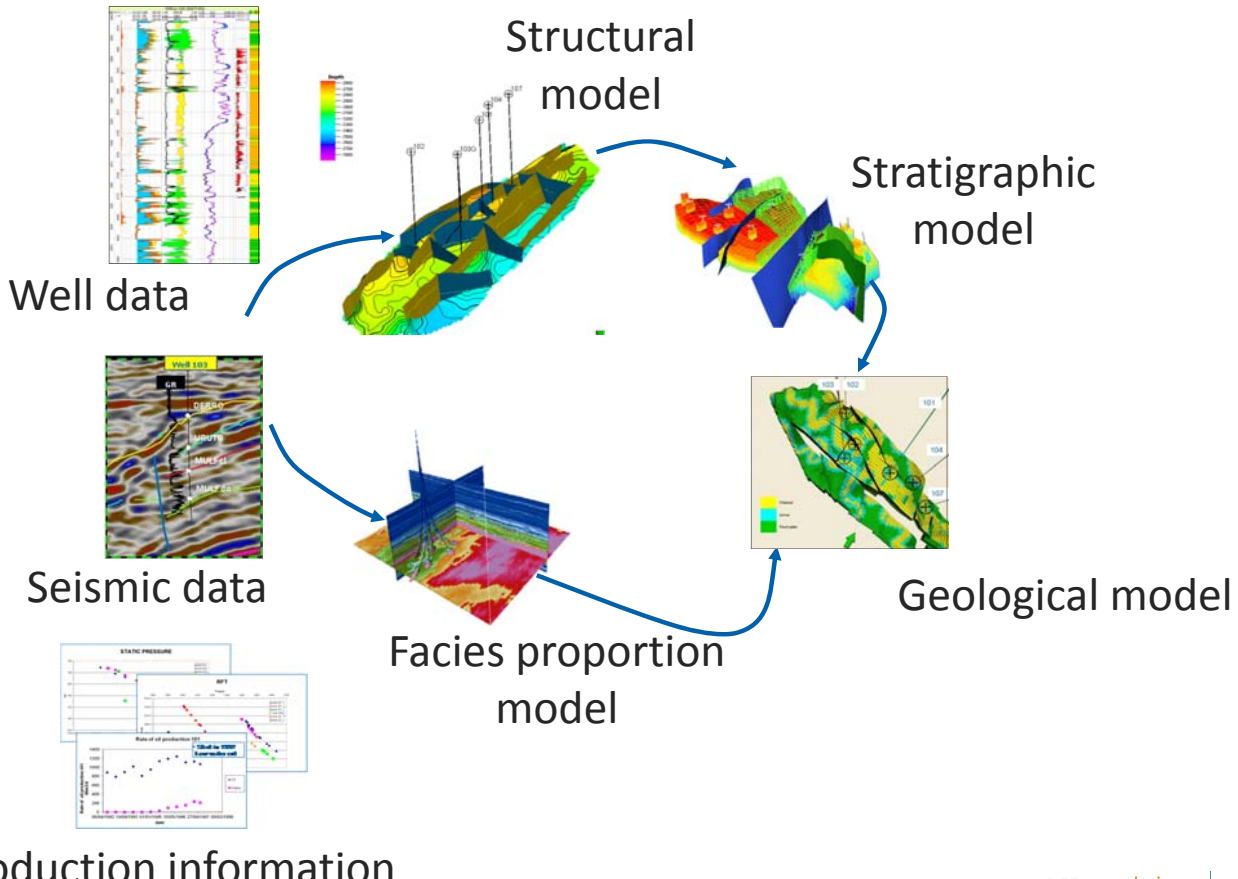
IFP Training

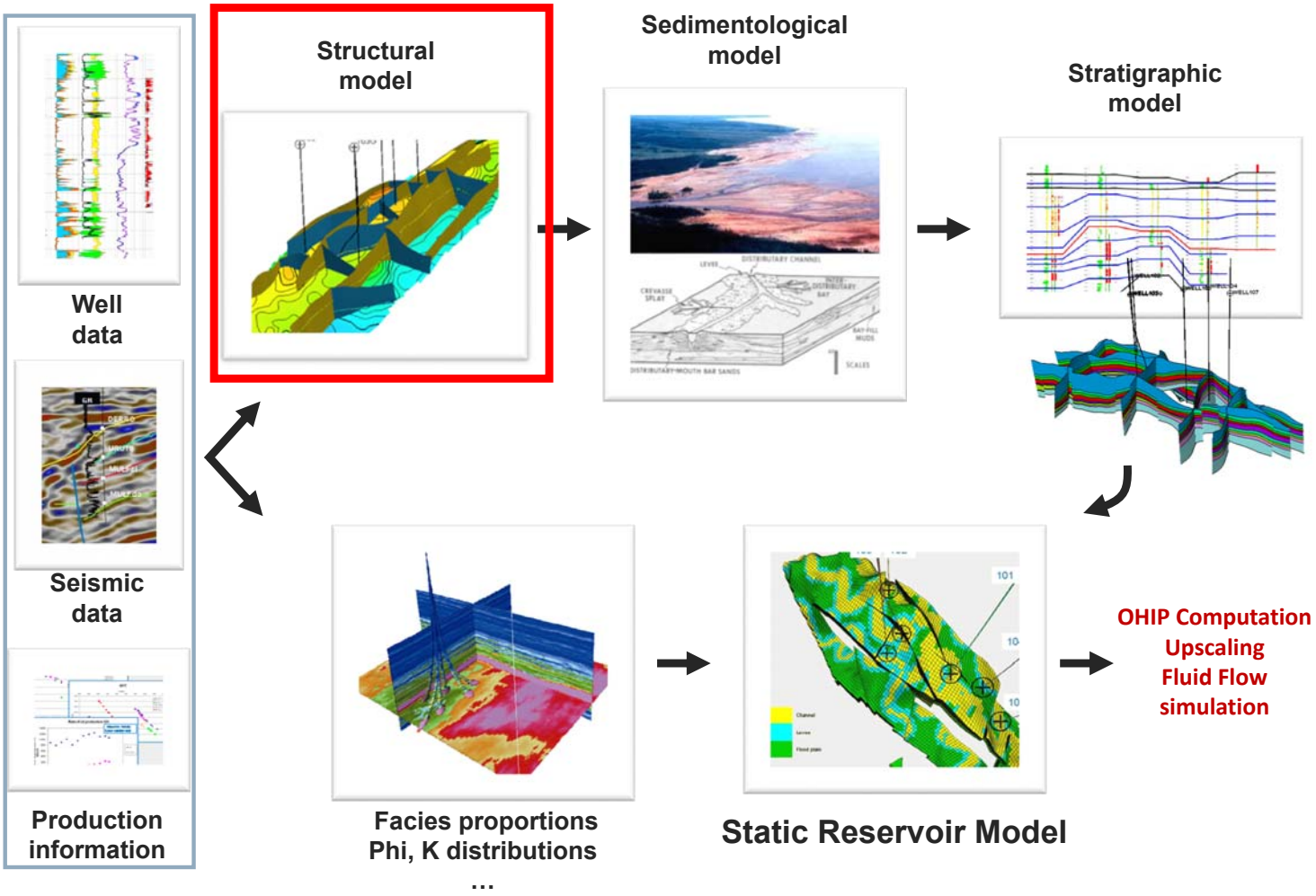
Sommaire

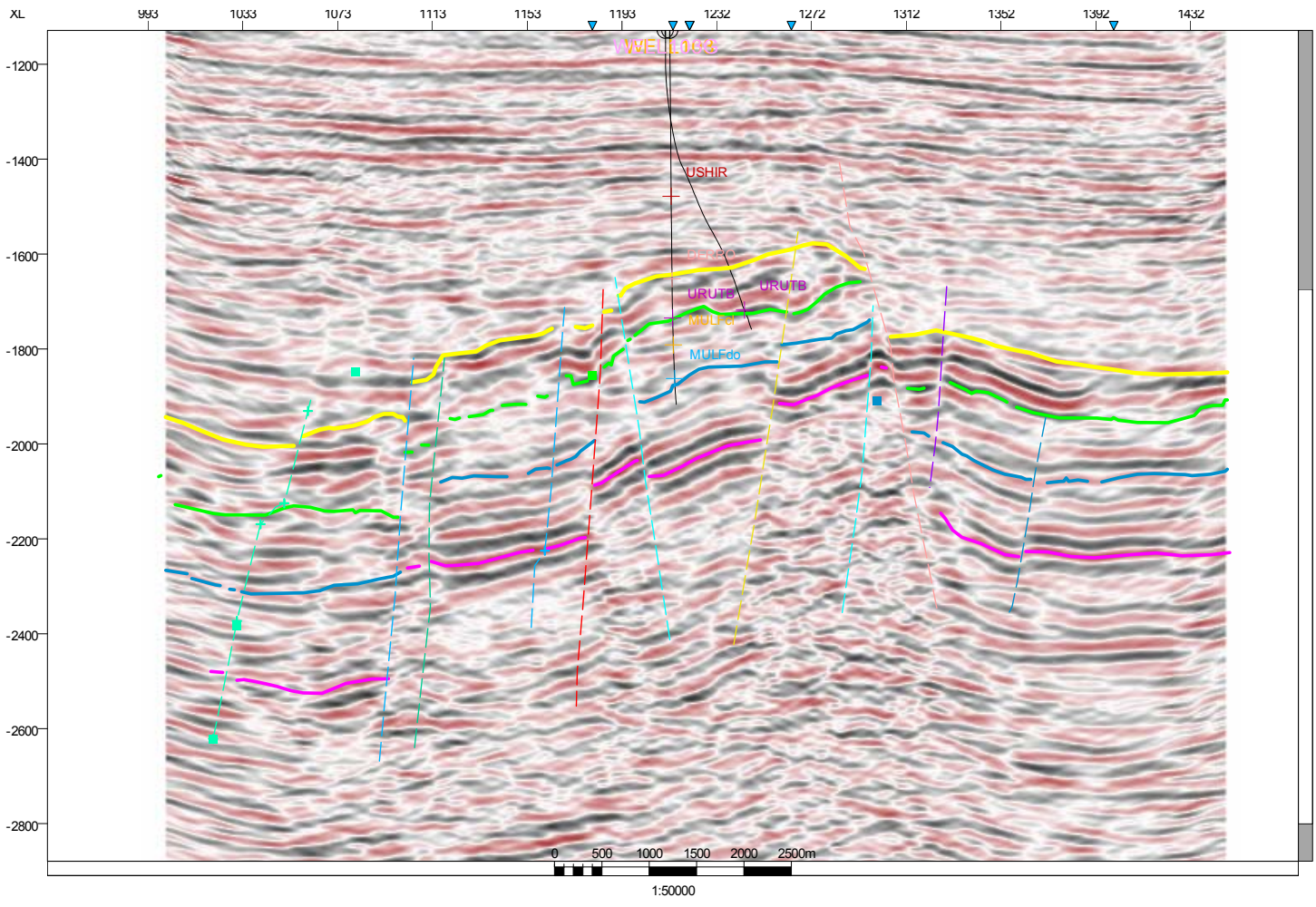
- Review en geological modeling workflow 141
- Reservoir description – Gridding 169
- Grid types 181
- Main issues in reservoir description 207

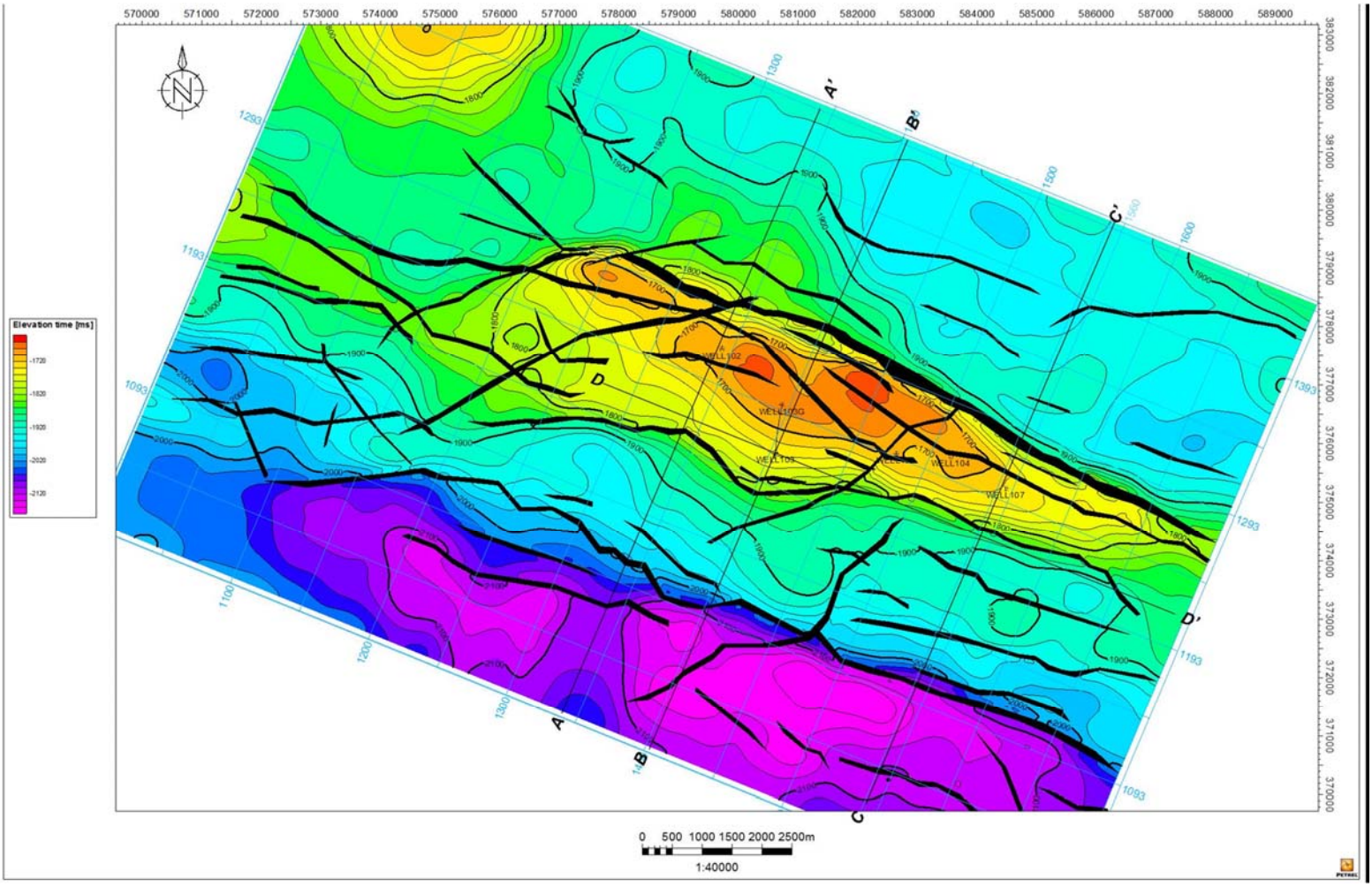
Review en geological modeling workflow

Field Integrated Study Workflow

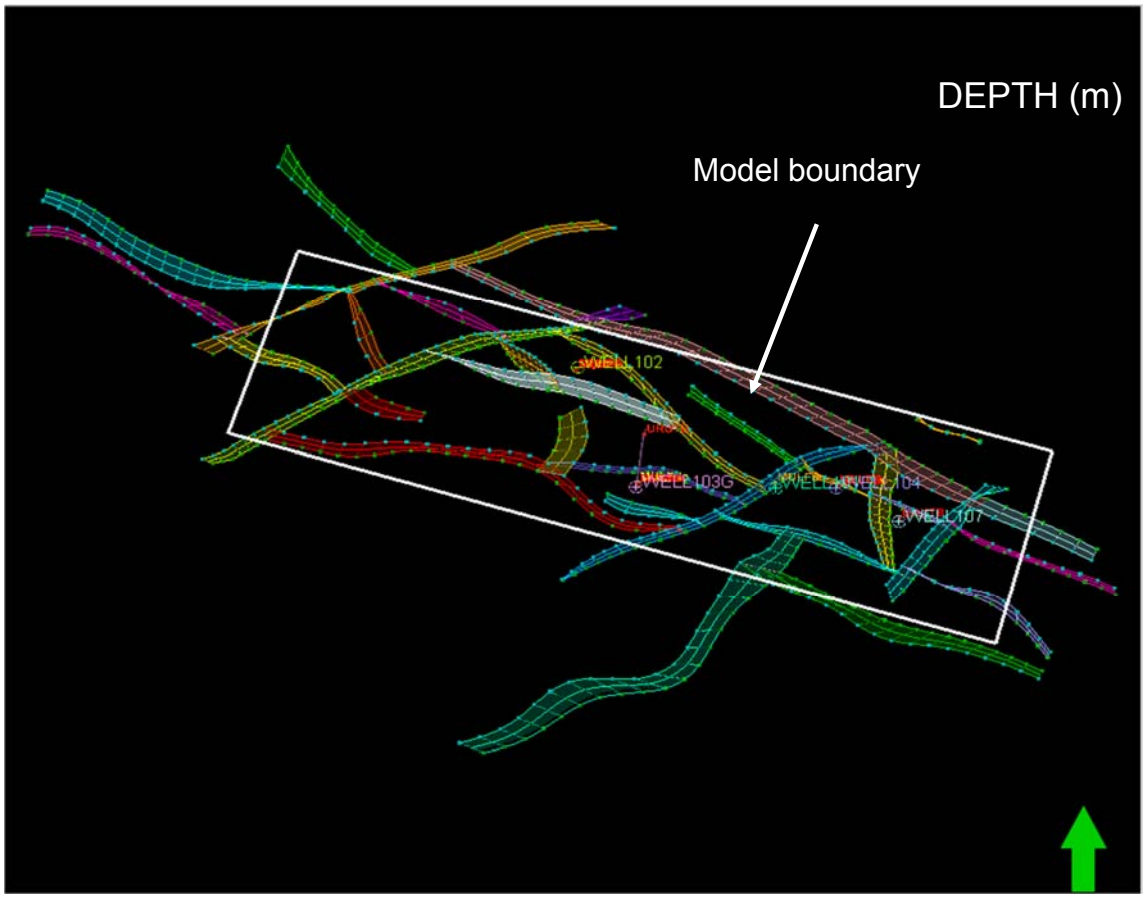



Structural model
Sedimentological model
Stratigraphic model
Well data
Seismic data
Production information
Facies proportions
Phi, K distributions
...
Static Reservoir Model
OHIP Computation
Upscaling
Fluid Flow simulation


XL
993
1033
1073
1113
1153
1193
1232
1272
1312
1352
1392
1432
-1200
-1400
-1600
-1800
-2000
-2200
-2400
-2600
-2800
WELL103
USHIR
URUTB
URUTB
MULFd
MULFdo
0
500
1000
1500
2000
2500m
1:50000



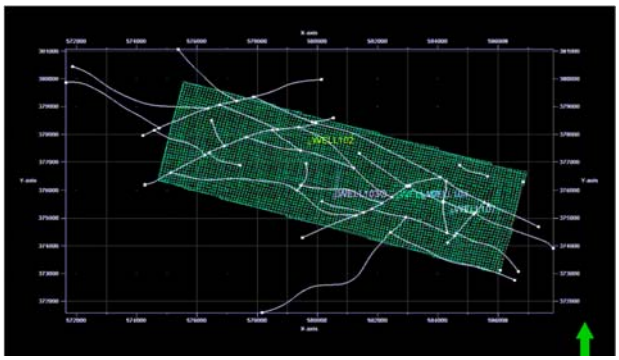
Selected faults (fault model)



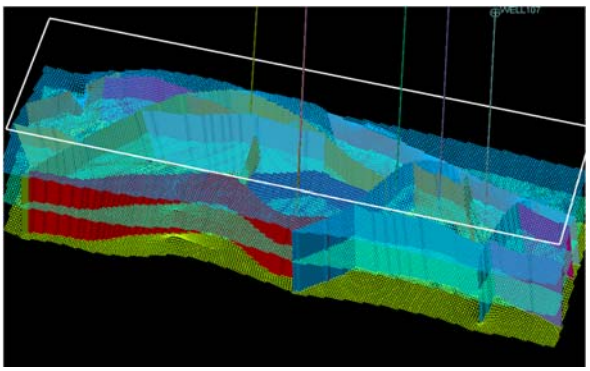
Construction of the structural model

- With the set of faults selected in the fault model
- Within the model boundary
- Pillar griding
- QC

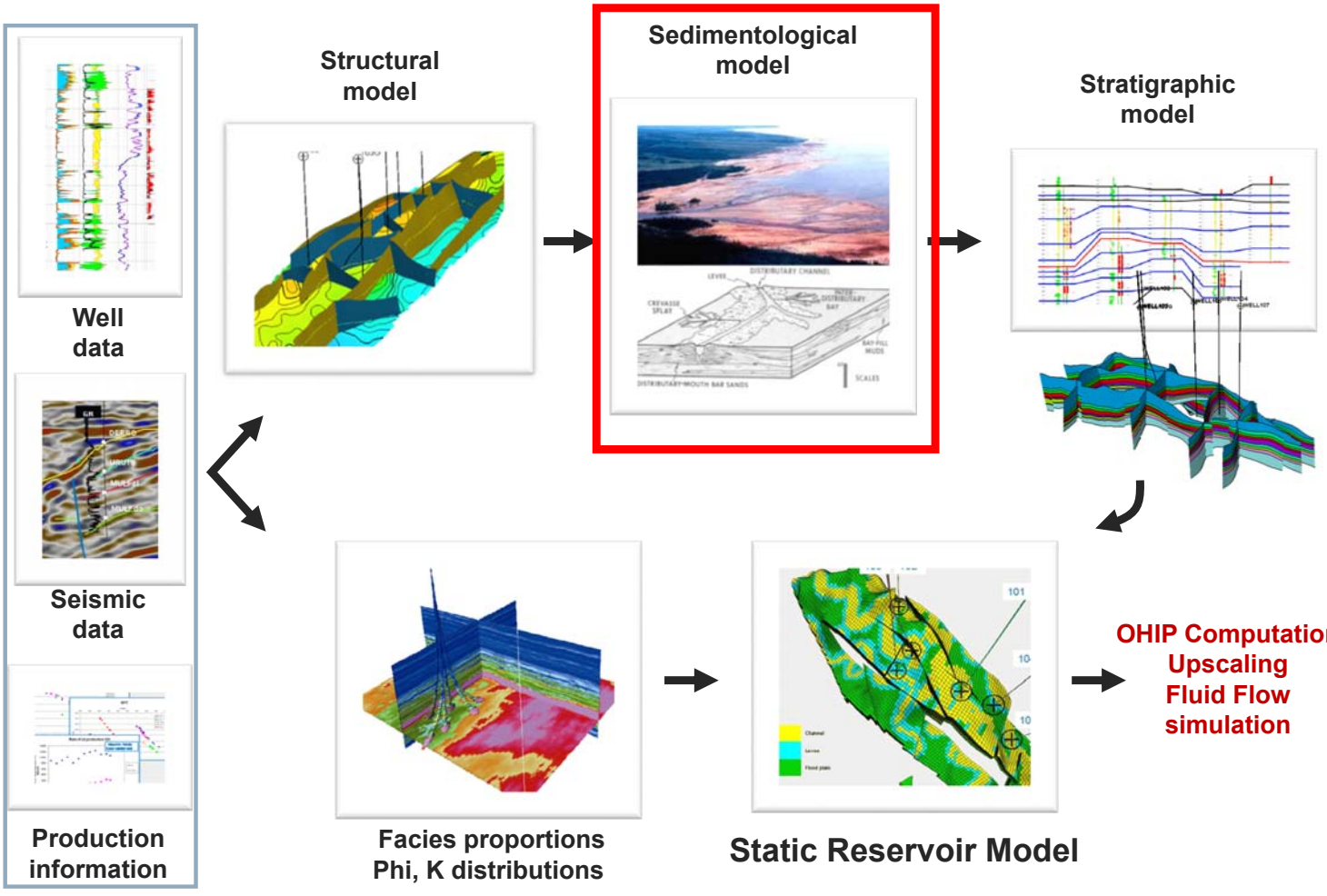
- Zigzag faults
- Interpreted surfaces
  - Top A
  - Top B
  - Top C
- Other surfaces
  - Interpolation between interpreted surfaces, constrained to well tops



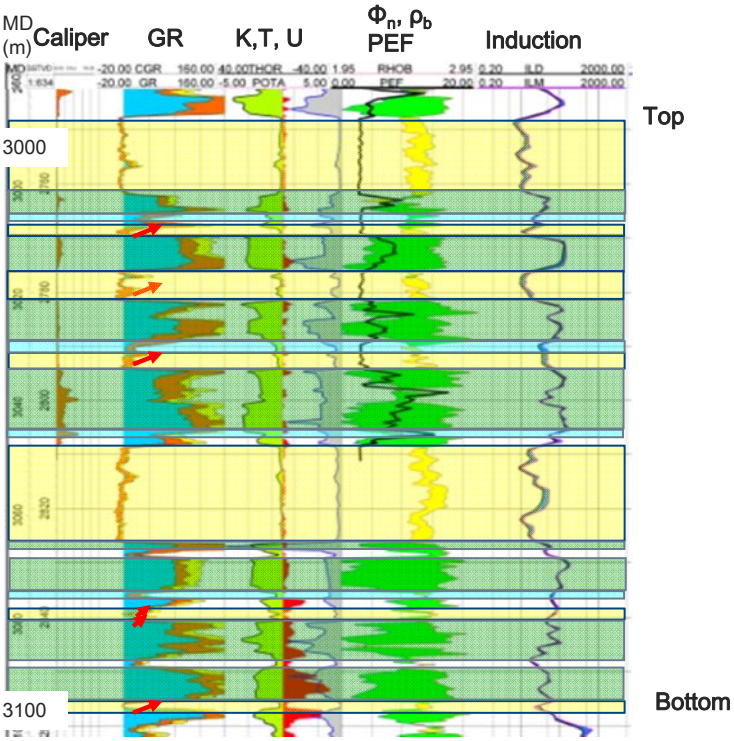
IN DEPTH (m)



IN DEPTH (m)



Depositional Environment A



Packages of sand in fluvial channels

Shaly packages of sand in levees

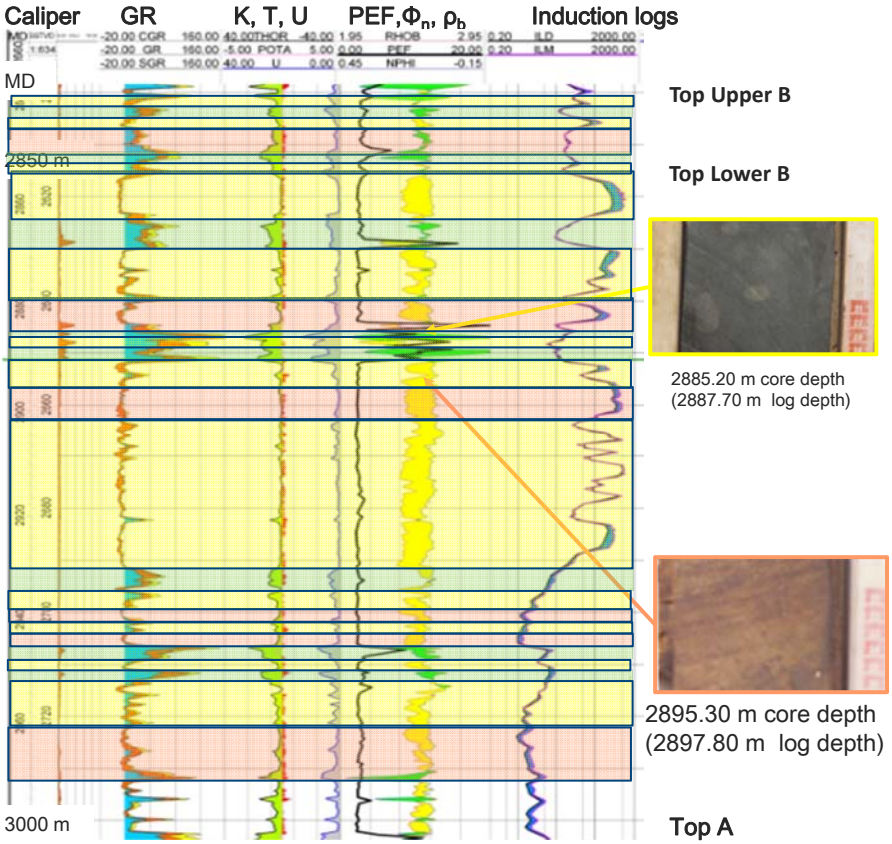
Shales packages corresponding to floodplains

FLUVIAL SYSTEM



Buchans Brook,
http://rainbowfish.angfaqld.org.au

Depositional Environment B



2885.20 m core depth
(2887.70 m log depth)

2895.30 m core depth
(2897.80 m log depth)

Interbedded fining upward packages of sand and shaly layers corresponding to **distributary channels**

Coarsening upward thick packages of sand corresponding to **distributary mouth bars**

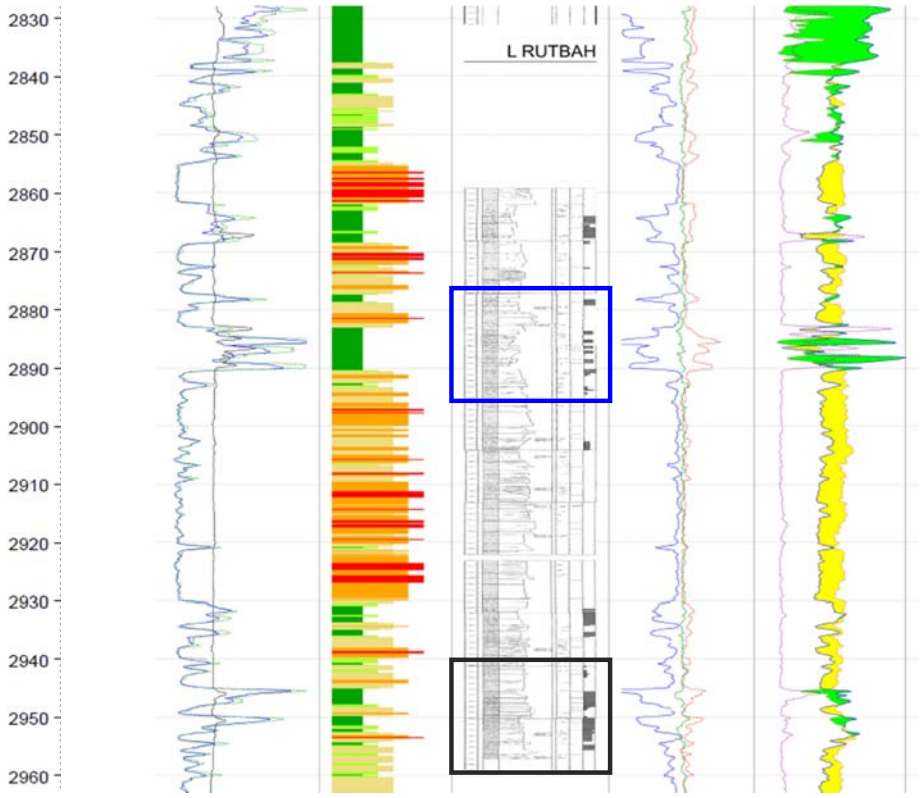
Deltaic shales

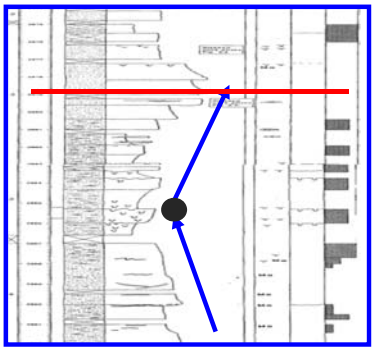
DELTAIC SYSTEM

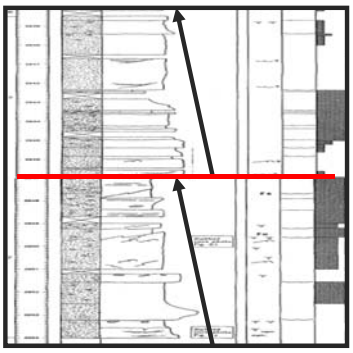


Buchans Brook, http://gsc.nrcan.gc.ca

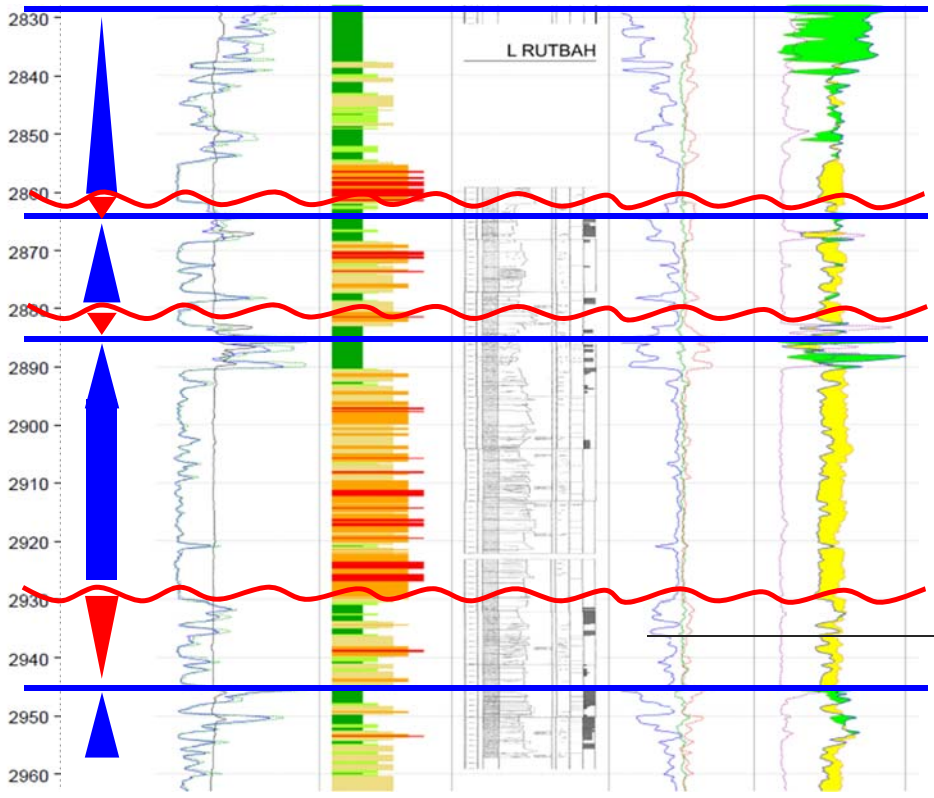
Sequence definition

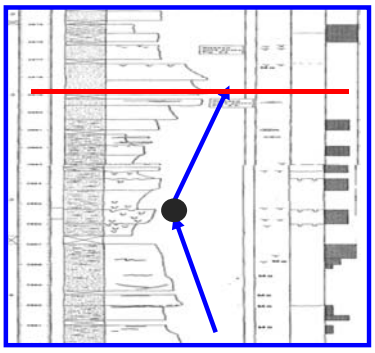


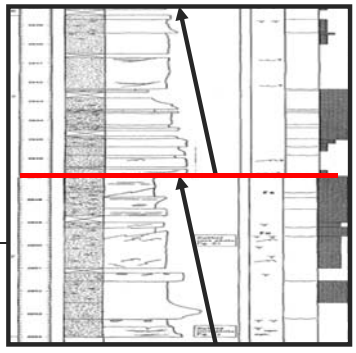


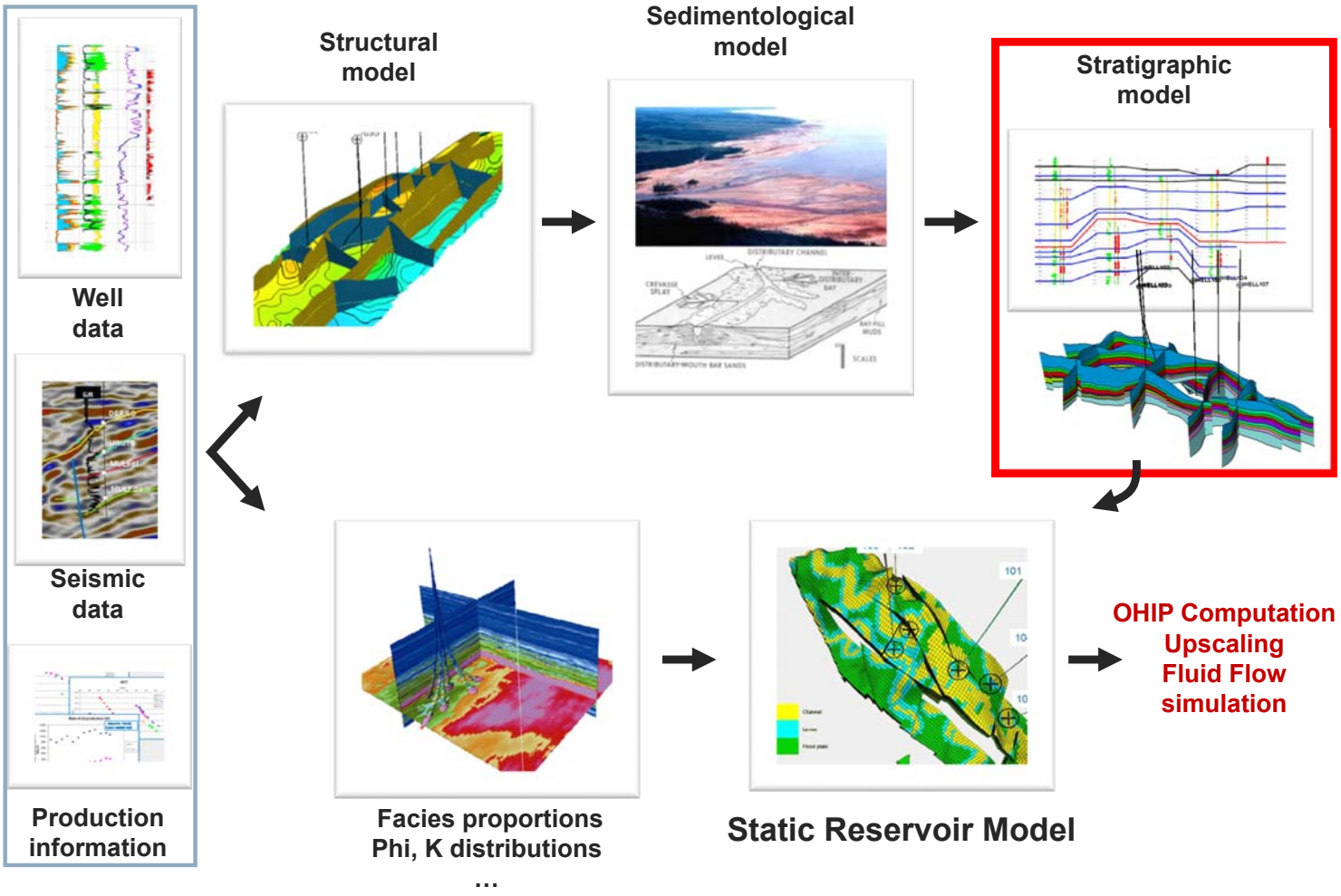


Sequence definition





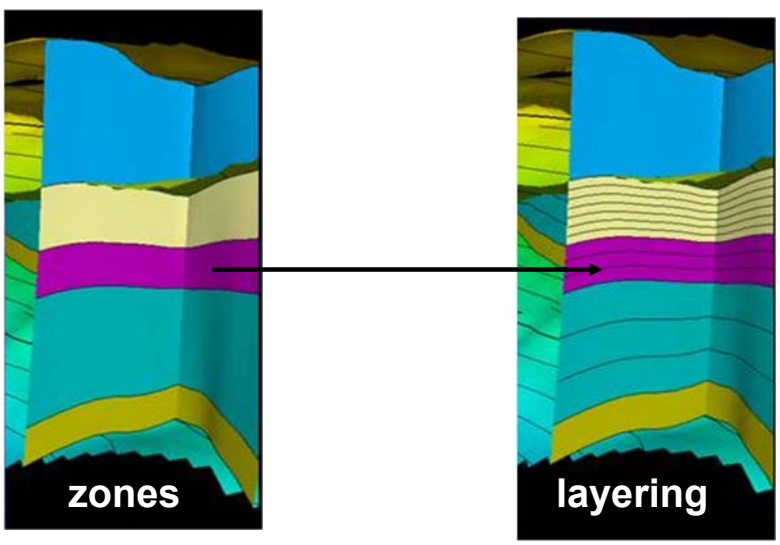




Layering

Reservoir geometry: stratigraphy

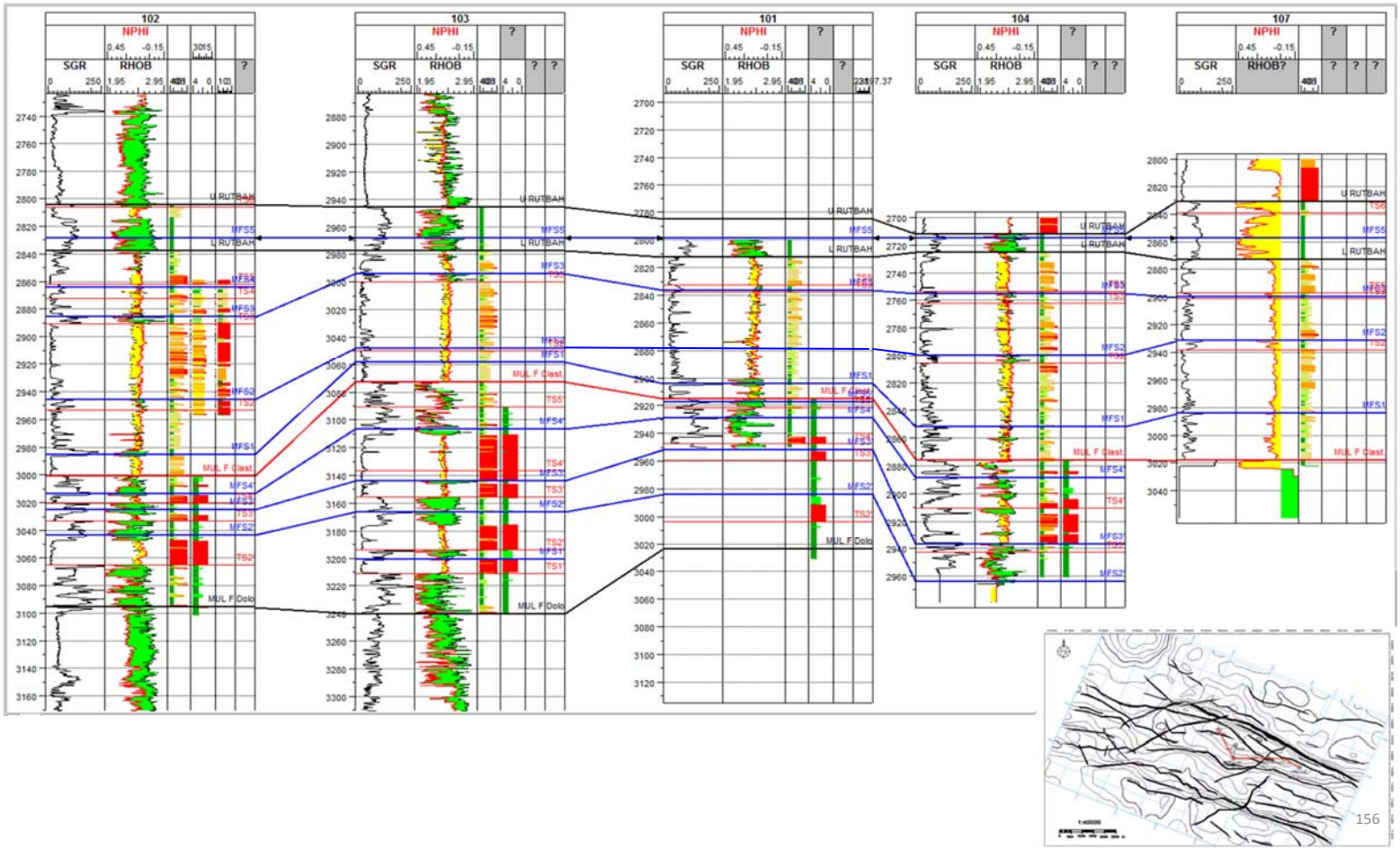
- Zones here corresponds to stratigraphic units. The objective is to refine the previous layering by creating the sub-layering corresponding to the units that one want to study using well markers and the previous horizons.
- The purpose is to define the grid on which the computations will be done. The averaging of properties is done when we upscale the well properties. Then, the grid is filled with average properties.



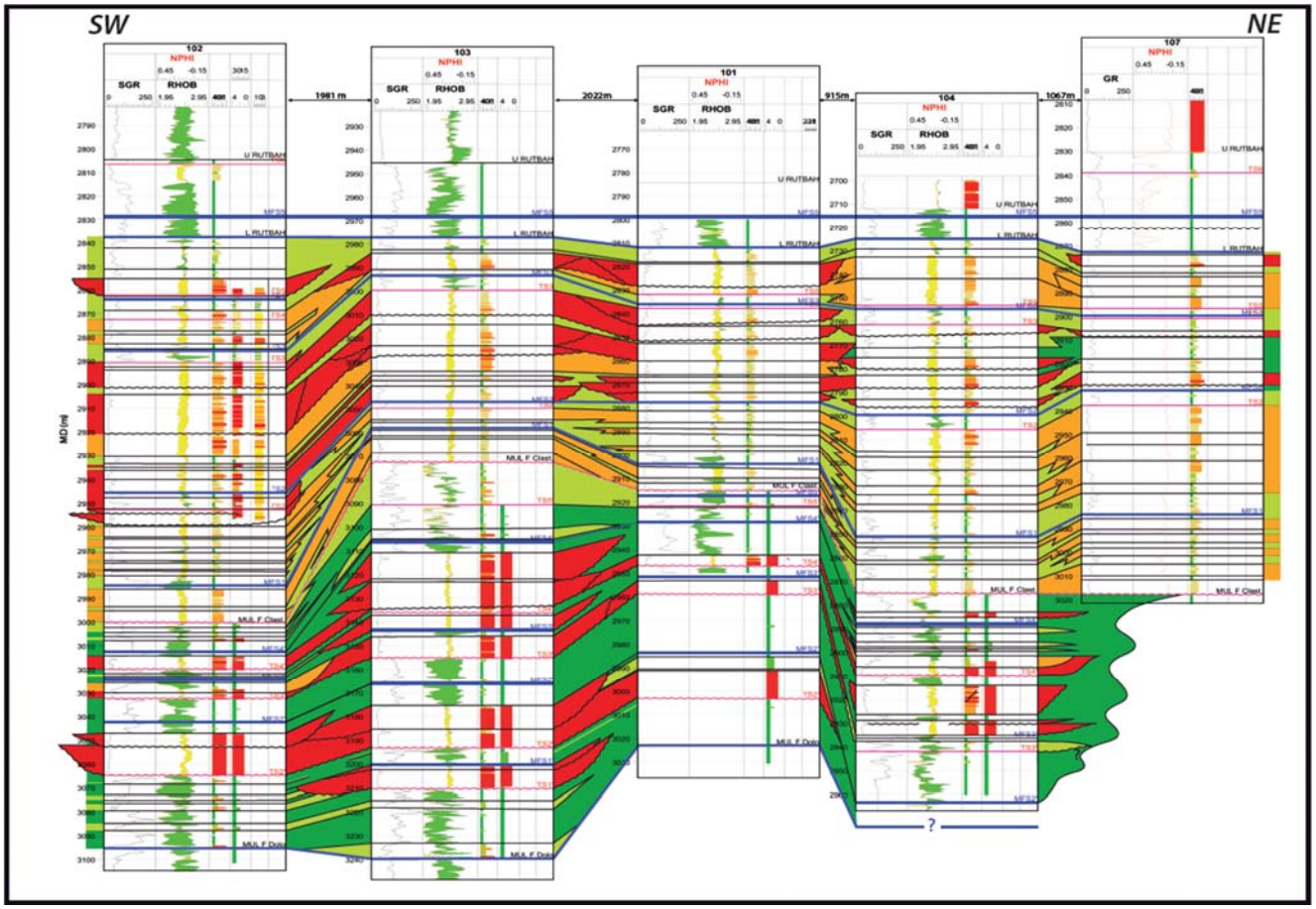
Layering

- **Goal: find an optimal number of layers**
- **Exact placement of layers will have a large effect only in models with correlated heterogeneities similar in scale to the displacement scale.**
- **Honouring geological features**
- **Honouring dynamic observations (RFT, PLT)**
- **Enabling to simulate the well completion**
  - Vertical
  - Horizontal
  - Selective, commingled
- **Enabling reasonable simulation duration**

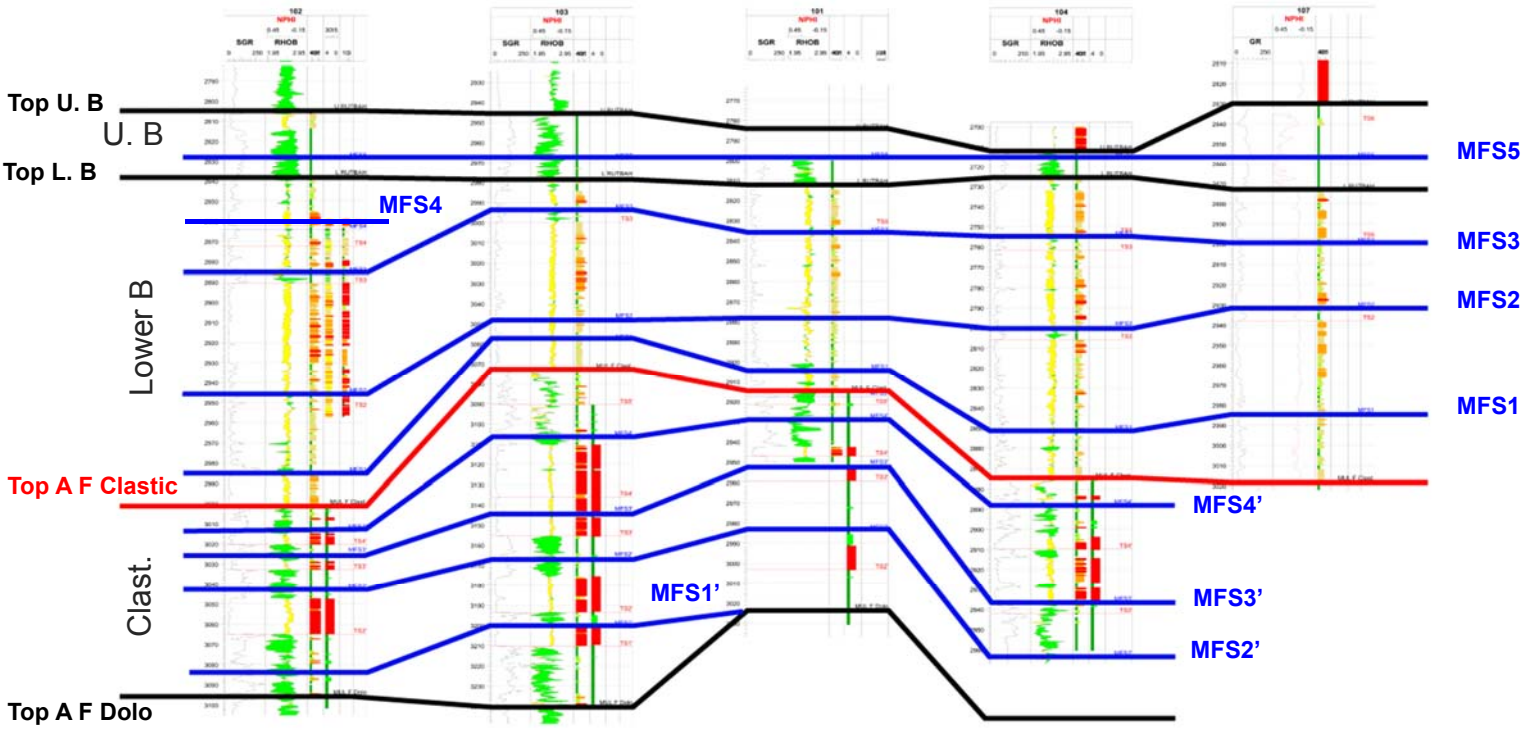
MFS Well to well correlation



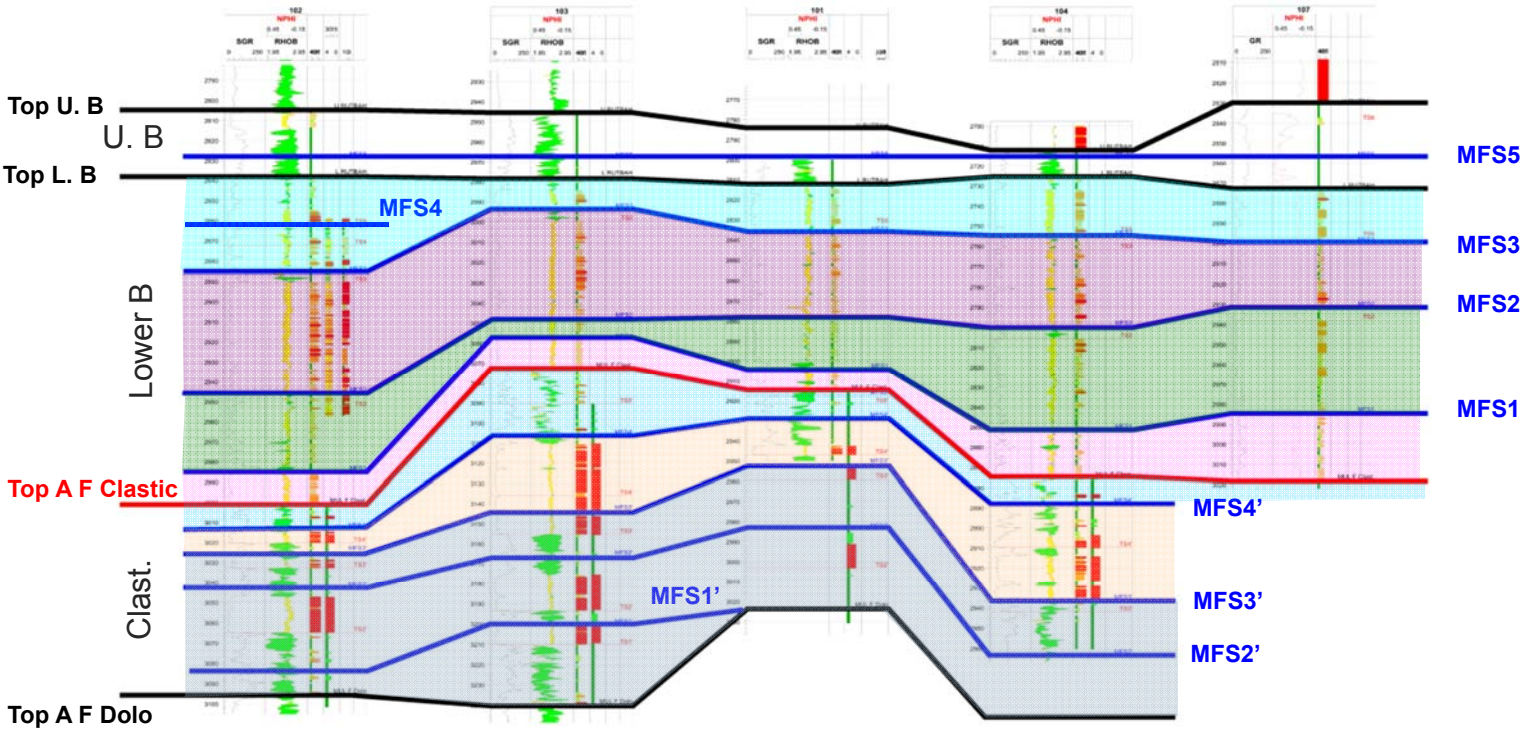
Stratigraphic model



Geological grid definition – Vertical layering

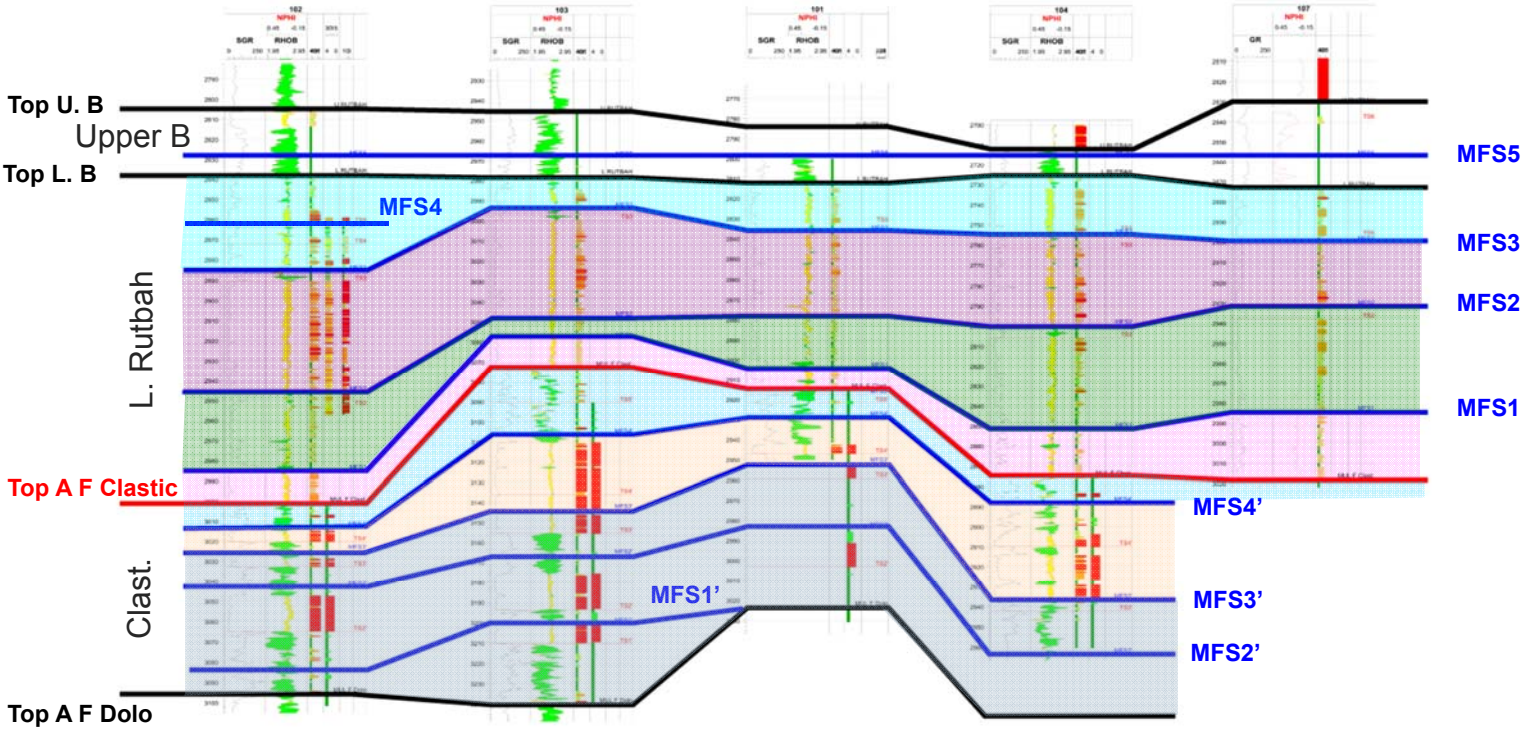


Geological grid definition – Vertical layering



Zone definition

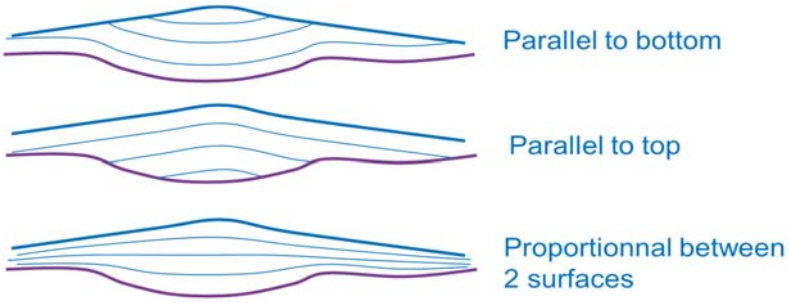
- Definition based on the stratigraphic model (MFS, TS, SB)



From conceptual to numerical model:

Layering

- **The type of layering must account for the depositional setting**
  - Parallel to a surface ?
  - Proportional ?



Make layers

Common settings

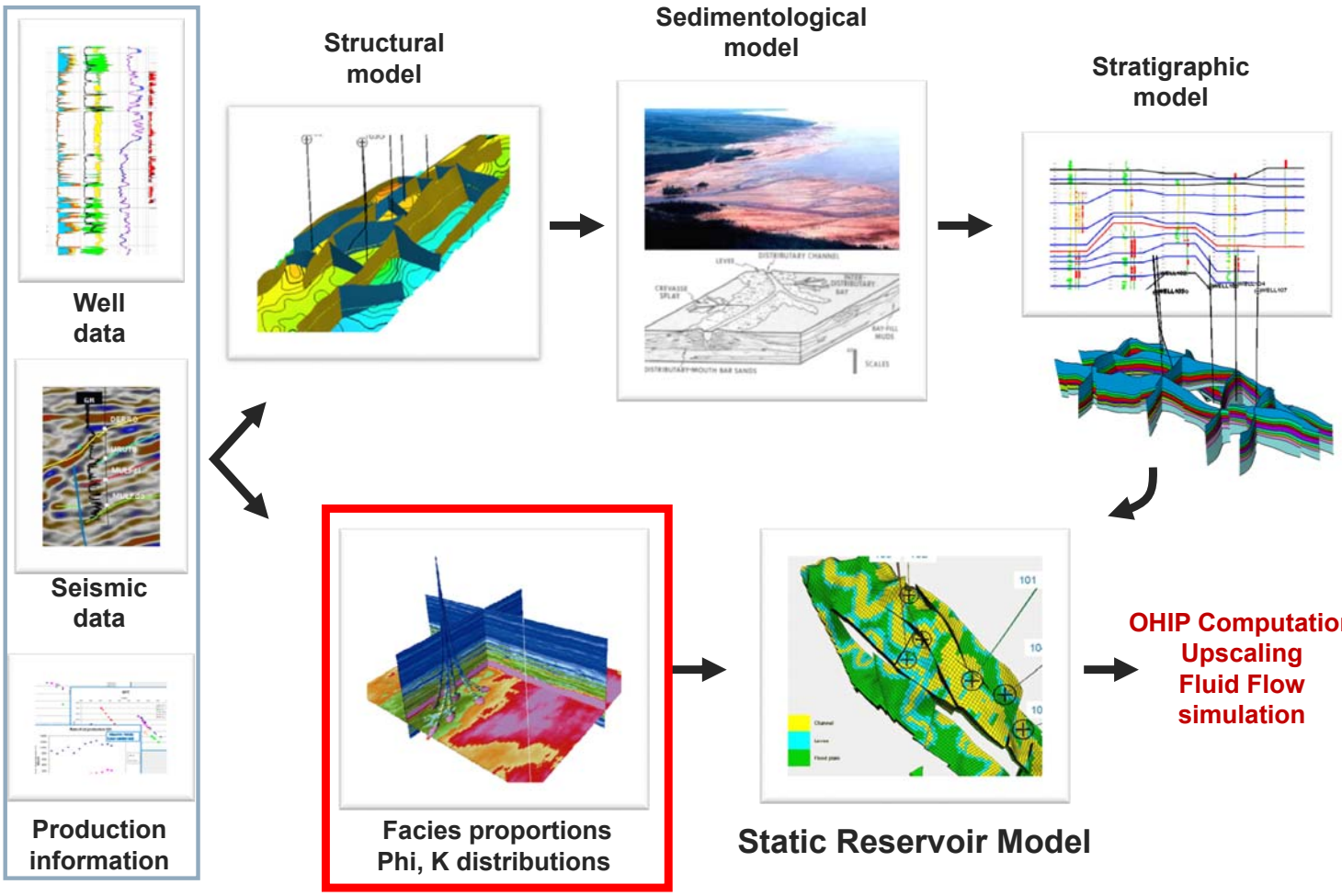
Build along: Along the pillars | Horizons with steep slopes

Use minimum cell thickness: 1 | Include proportional/fractions, start from: Top

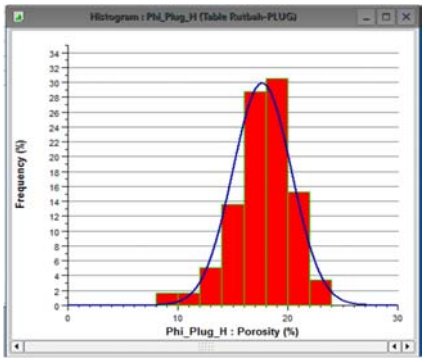
Zone specific settings

Zone division: | Reference surface: | Restore eroded: | Restore base:

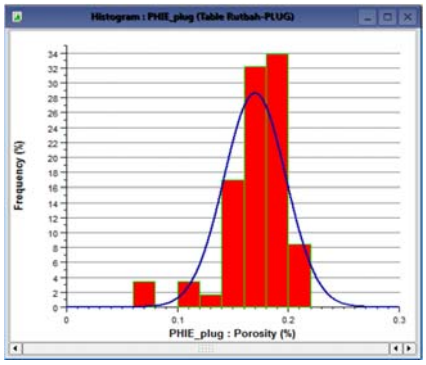
Name	Color	Calculate	Zone division			Reference surface	Restore eroded	Restore base	Status
Tarbert		Yes	Proportional	Number of layers:	60		Yes	Yes	Done
Ness2		Yes	Follow top	Cell thickness:	5.00		Yes	Yes	Done
Ness_1		Yes	Follow base	Cell thickness:	5.00		Yes	Yes	Done
Lower Bre		Yes	Proportional	Number of layers:	1		Yes	Yes	New



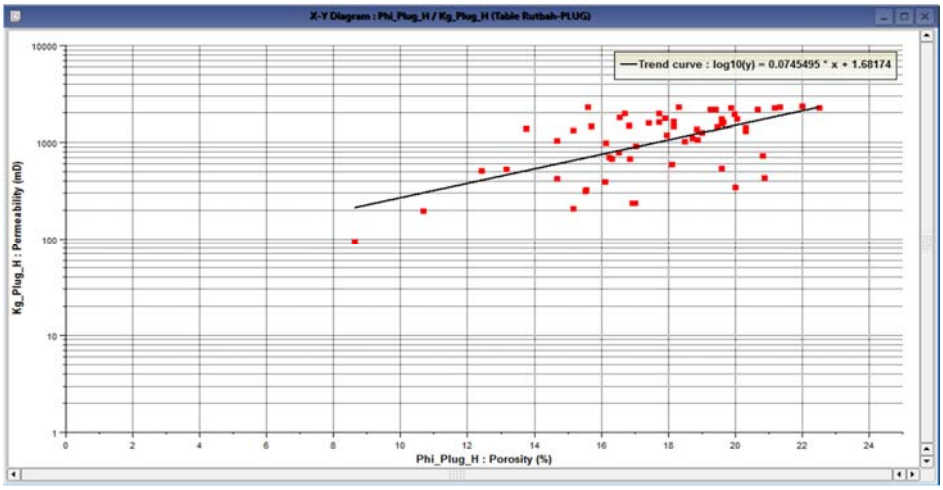
Rock-Typing



Phi_Plug



EX: RT1

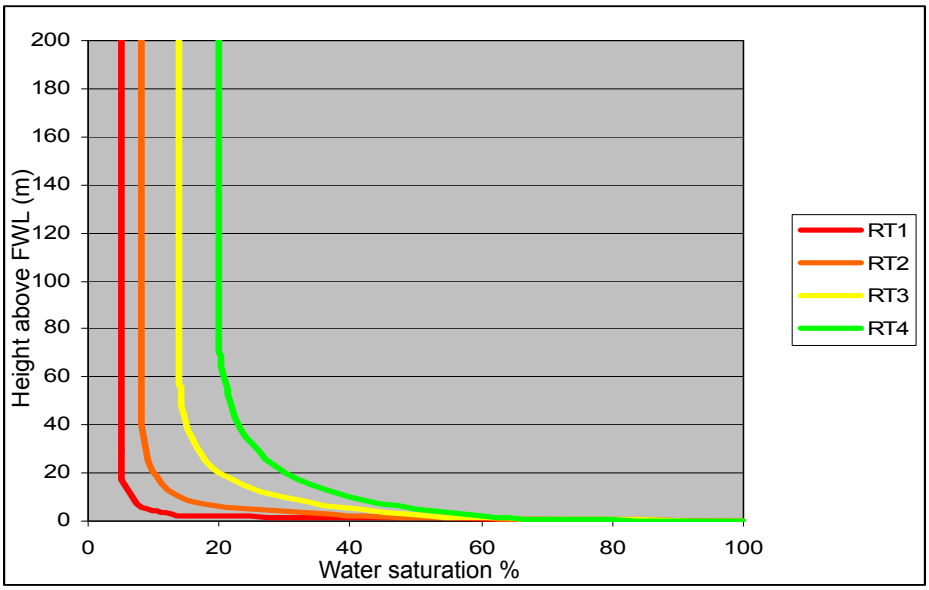


Phi – Log(K) Law

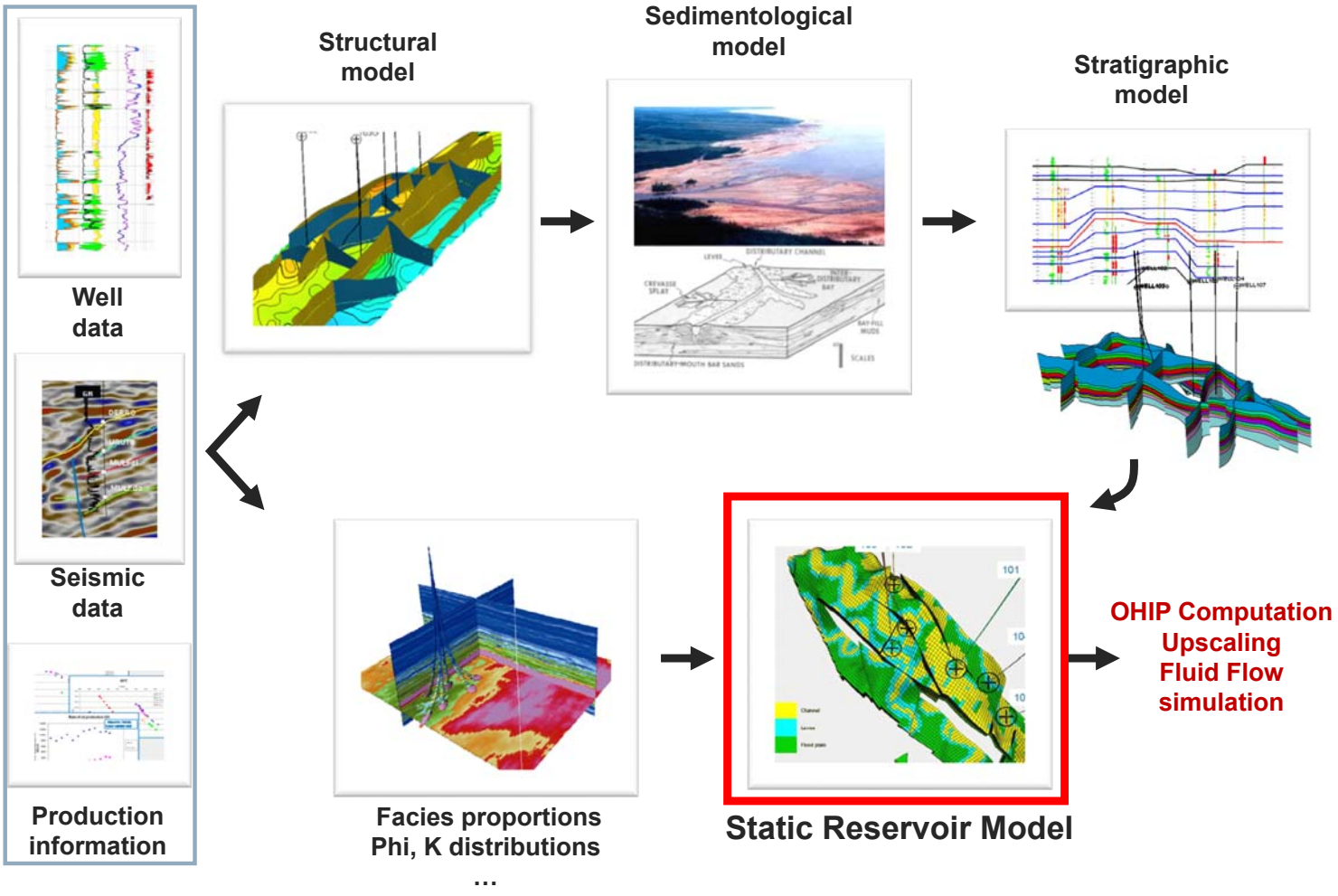
➔ K attribution to electrofacies

Rock Types definition (Fluid flow model)

Rock type	RT1	RT2	RT3	RT4	RT5
Porosity	> 15%	12.5 to 15%	10 to 12.5%	8 to 10%	
Irreducible SW	5%	8%	14%	20%	45%
Kv/Kh	0.8	0.5	0.1	0.05	0.05

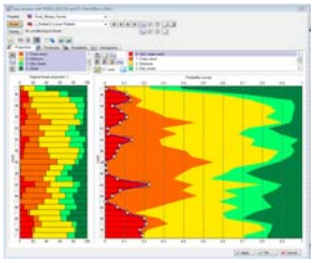


Curve Sw vs. Heigth above Free Water Level

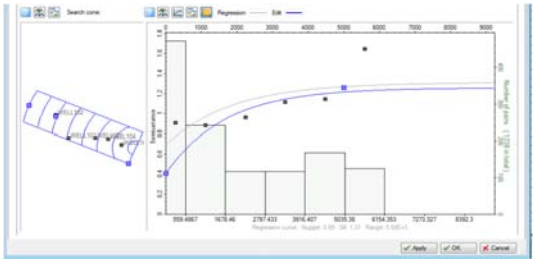


Rock Type simulation

- **Zone by zone**
- **With the layering adapted to the depositional setting**
  - Choice of a simulation method for Facies
    - U. Rutbah : pixel-based



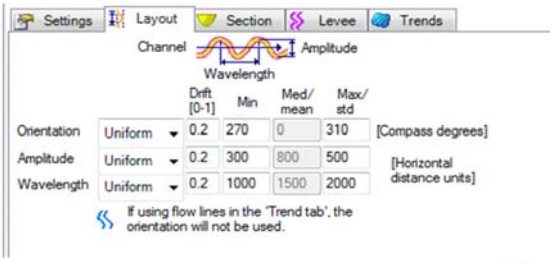
vertical proportion curve



variograms

- Mul. Clast : object based

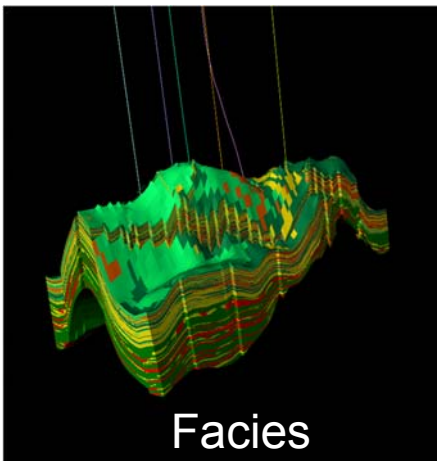
definition of the geometry of objects

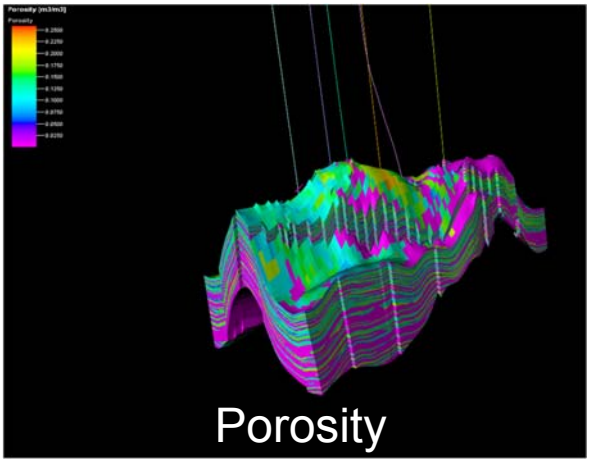


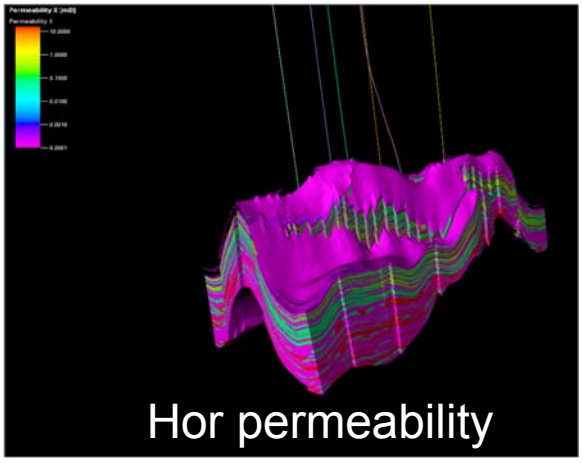
Petrophysical modeling

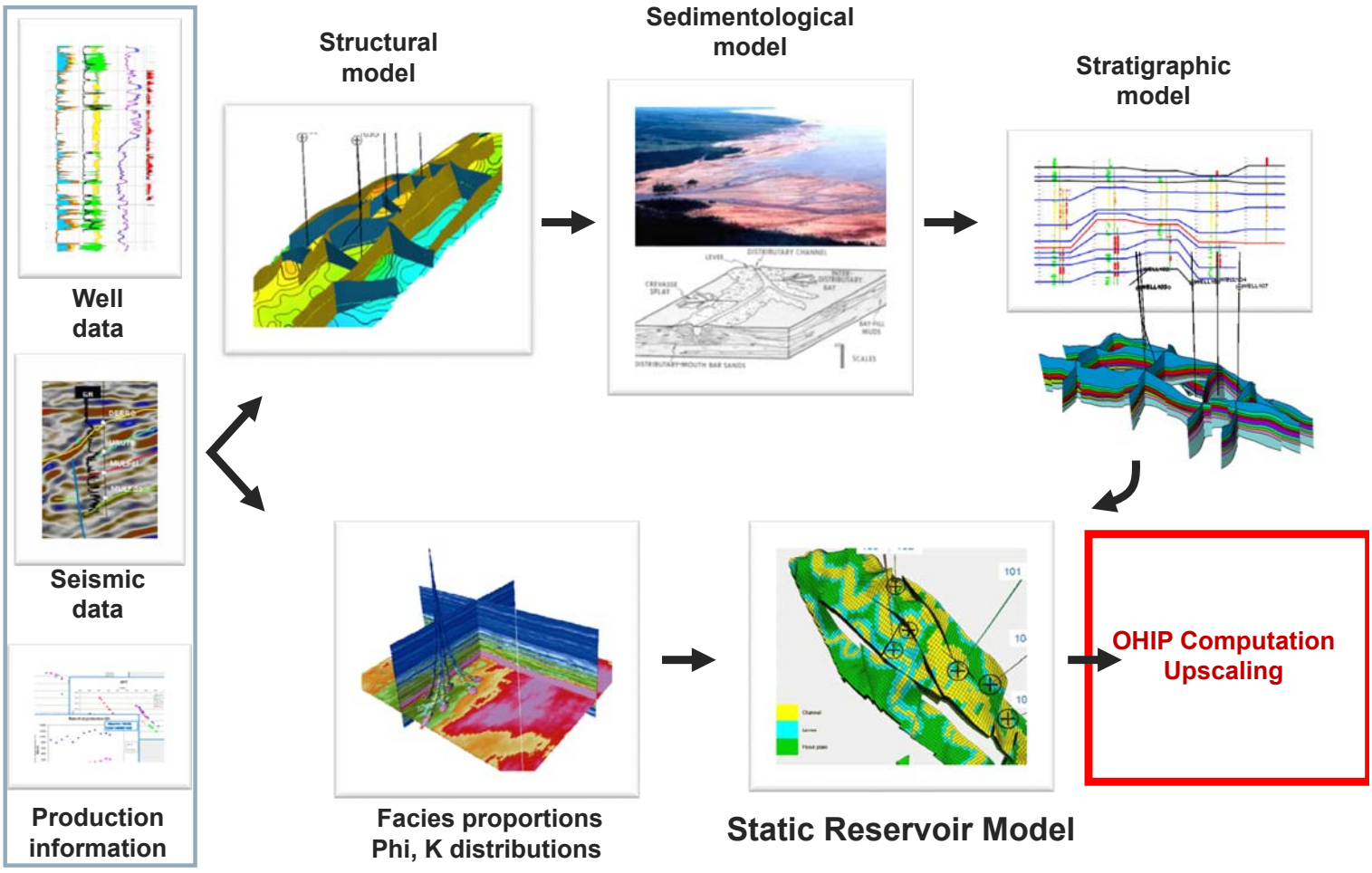
Simulation results

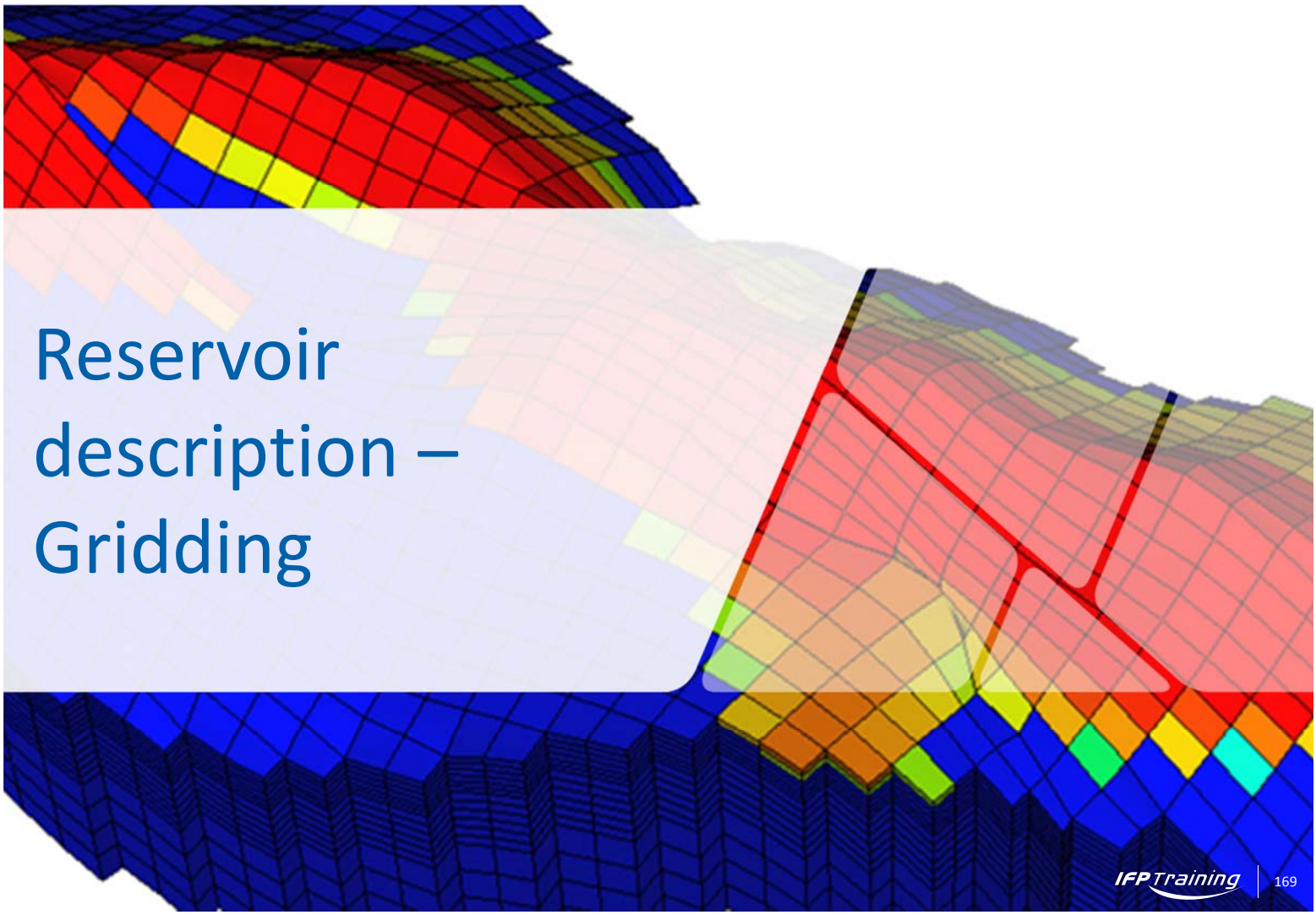
- Definition of the Porosity distribution
- Correlation law between Log(K) and Phi











Reservoir description – Gridding

Reservoir simulation model

1 Reservoir simulation model

=

1 Numerical calculator

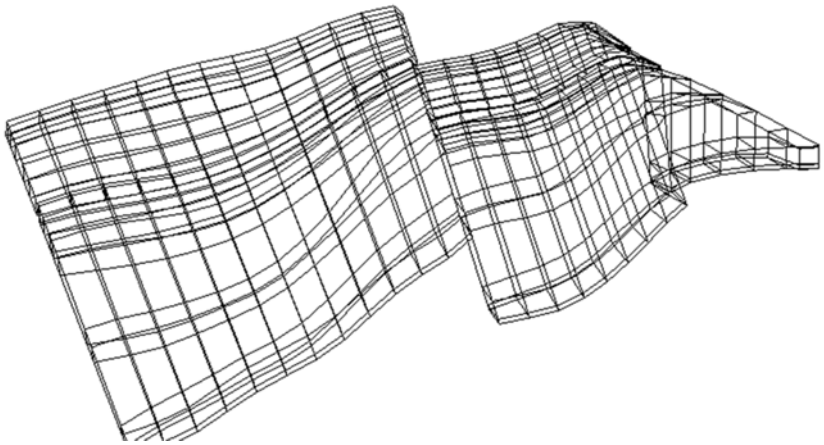
+

1 Set of modelled data

Gridding

- **In a numerical model, space is discretized and the reservoir volume is described as a series of contiguous cells defined by a grid system.**
- **The finite-difference formulation of the reservoir simulation problem requires that the reservoir be segmented into a pattern of mesh points or gridblocks**

- **Important parameters are:**
  - The grid type
  - The cell size
  - The number of cells



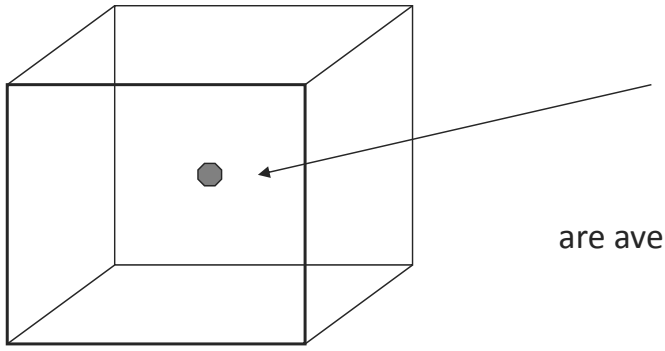
Reminder

Numerical Simulator Basic Parameters

- **Reservoir (volumetric)**
  - Gross volume: Vt
  - Net volume: Vu
  - Porous volume: Vp
  - Pore compressibility: Cp
- **Fluids**
  - Pressure: Po, Pg, Pw
  - Saturation: So, Sg, Sw
  - Density: ro, rg, rw
  - Viscosity: µo, µg, µw
  - Compressibility: Co, Cg, Cw
  - Compositions: xi, yi
- **Flows**
  - Permeability: Kx, Ky, Kz
  - Capillary pressure: Pcwo = Po - Pw, Pcgo = Pg - Po
  - Relative permeability: Krow, Krw, Krog, Krg

Required properties

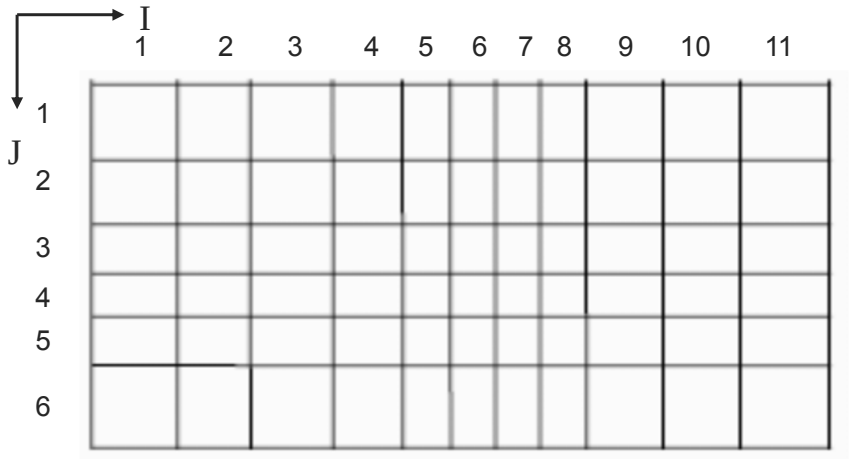
- **For each cell in the model, the following properties are required:**
- **Geometry; identification of log correlations**
  - Cell dimensions (x,y,z) and depths
- **Properties**
  - Porosity
  - Permeability
  - Net to Gross or net thickness (if not indicated, usually assumed to be equal to 1)



Cell properties such as:
PORO
PERMX
PERMY
PERMZ
NTG
are averages defined at the centre of the cell

Geometry

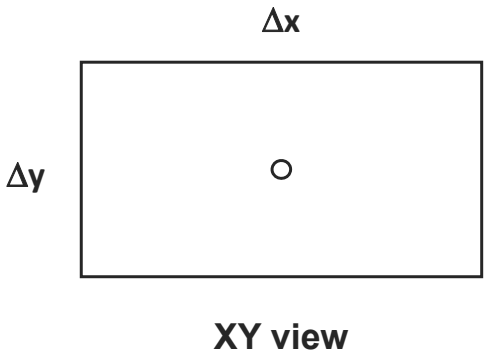
- **Rectangular grids: defined aerially by x columns and y rows**



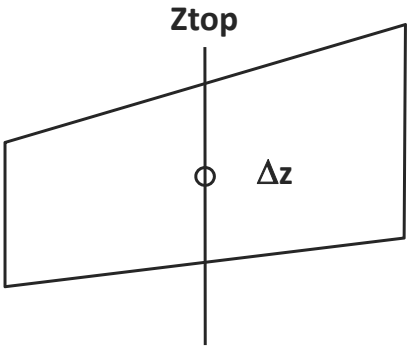
- **All columns have the same number of rows**
- **All the cells in one column have the same length Δx**
- **All rows have the same number of columns**
- **All the cells in one row have the same width Δy**

Geometry

- Depths are defined at the grid block centre



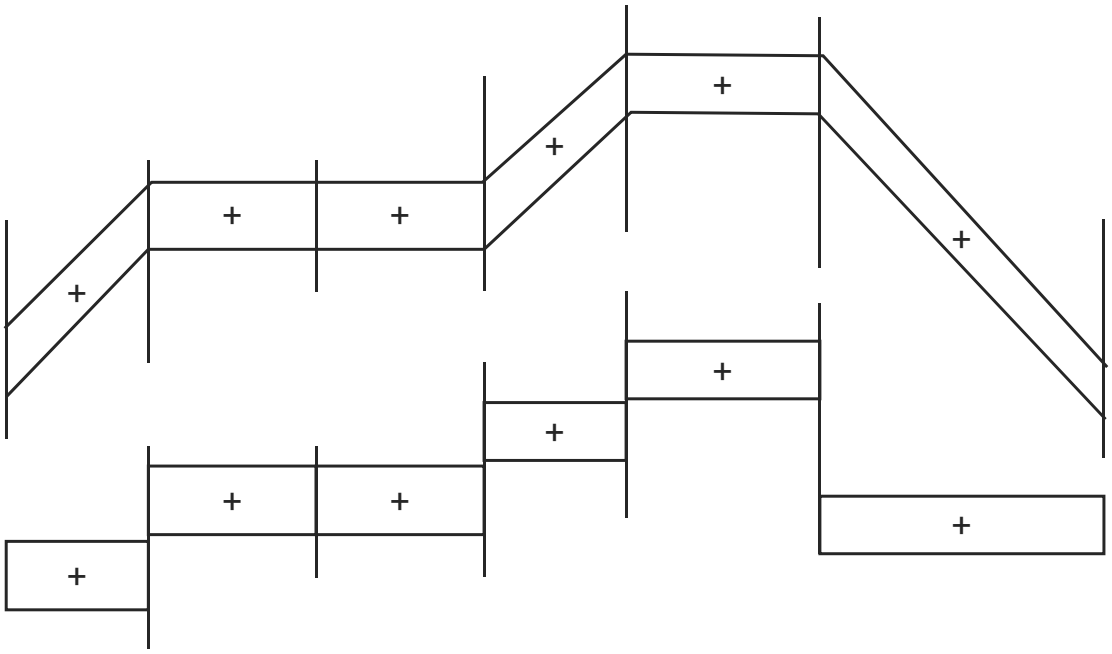
XY view



XZ section

- Cell volume is Vt = Δx . Δy . Δz

Grid

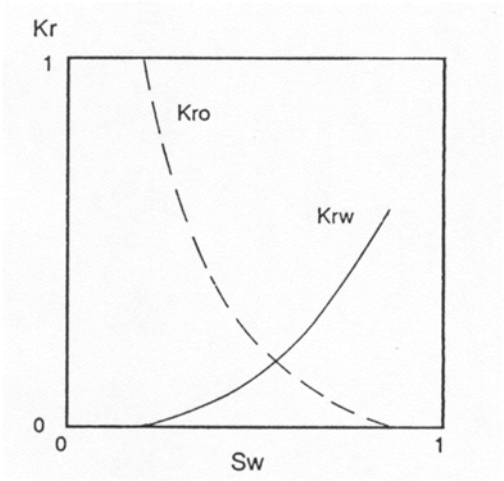


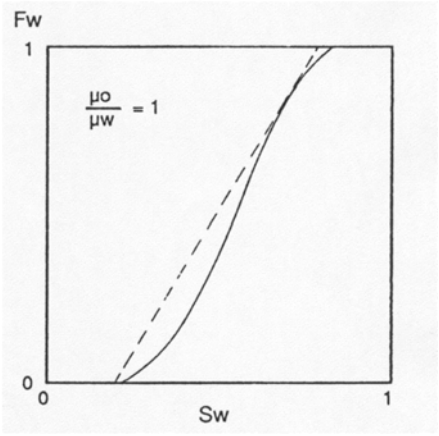
Grids I et II are equivalent

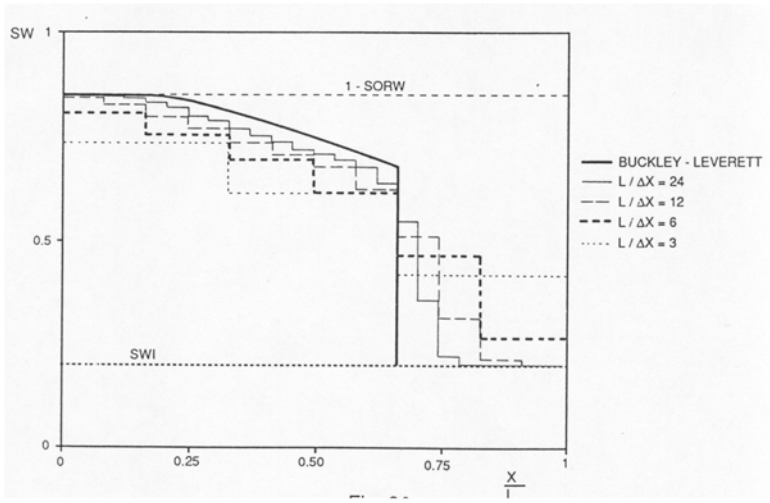
Consequences of gridding

- Numerical dispersion
- Drawback of numerical techniques that can cause errors in simulation of processes involving rapid changes in saturation
- No satisfactory way to eliminate numerical dispersion
- Using of a large number of gridblocks reduces numerical dispersion

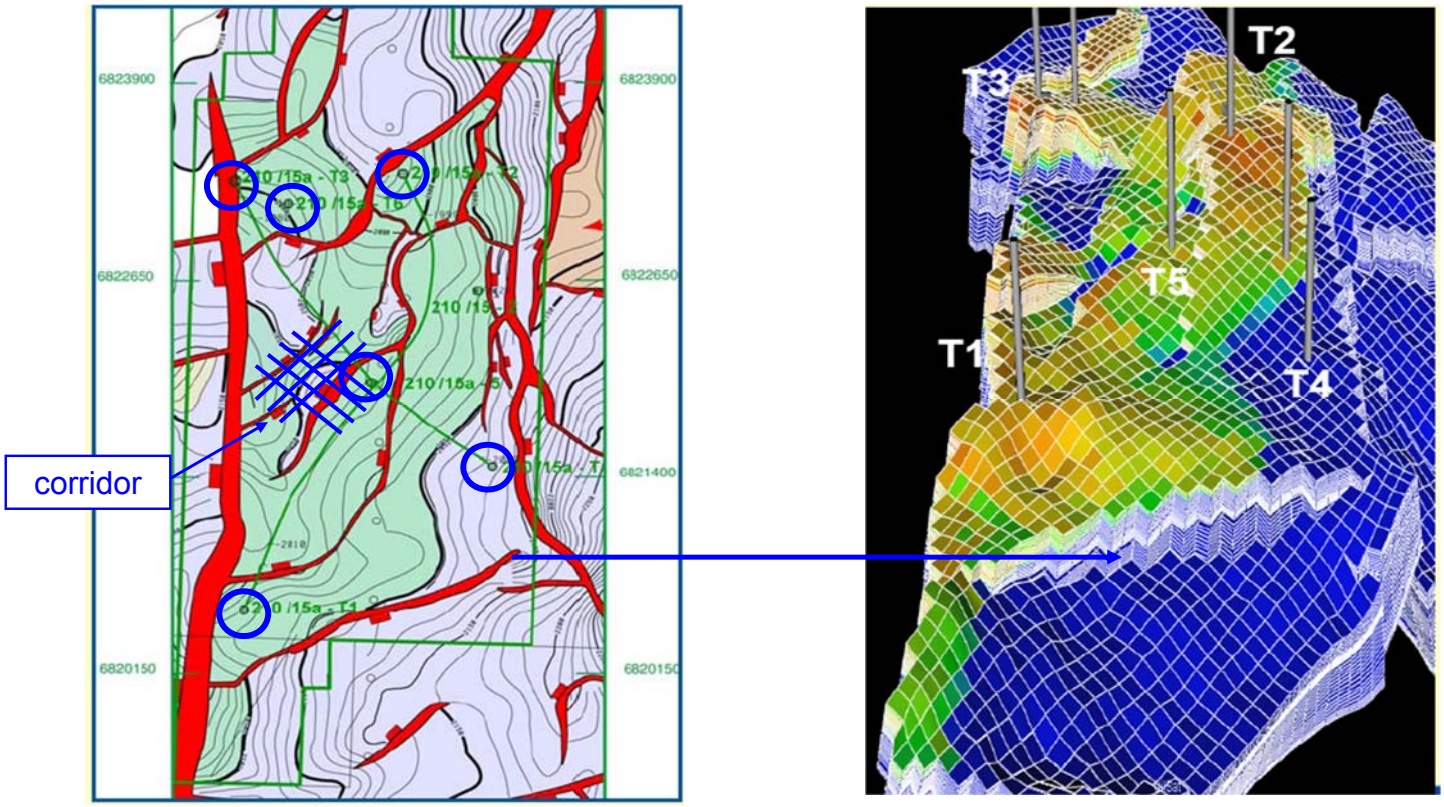
Consequences of gridding





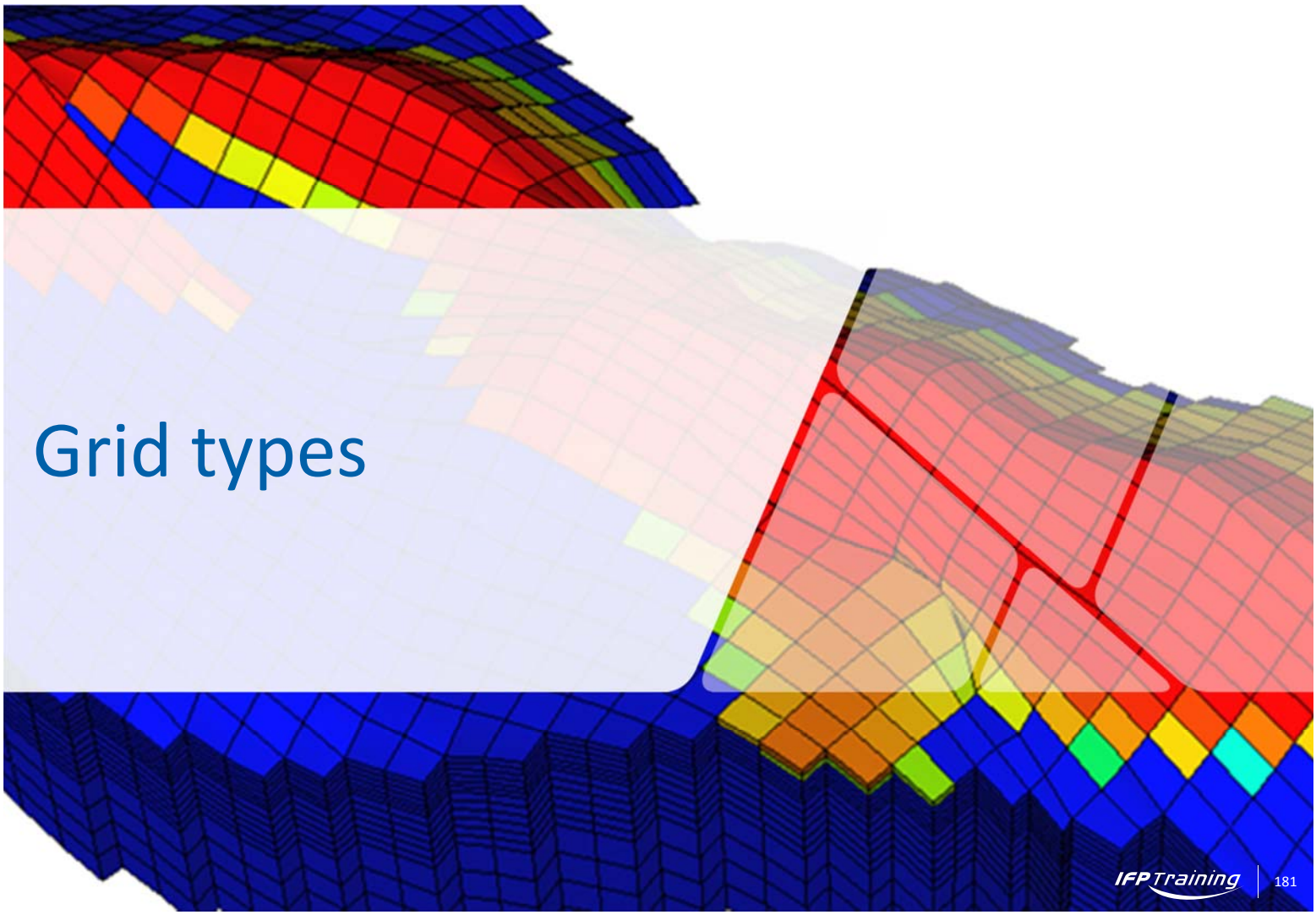


Gridding: grid orientation



Consequences of gridding

- Grid orientation effect
- P and Saturations are distorted by grid orientation
- As a consequence calculated performance is affected by grid orientation
- Effect is higher when displaced phase is less mobile than displacing phase



Grid selection

- **Grid selection will result from a trade-off between**
- **Good vertical and horizontal reservoir description for:**
  - Structure
  - Faults
  - Heterogeneities: vertical – horizontal
  - Initial fluid interface: WOC – GOC
- **Accurate saturation front description**
  - Near wells
  - Near fluid interfaces Water-Oil and Gas-Oil
  - Between injection and production
- **Account for well location: present and future**
- **Optimization of the number of cells**

Gridding rules

- **Choosing a 3D grid consists in finding a compromise between various constraints such as:**
  - Geological constraints
  - Dynamic (flow, production) constraints
  - Simulation constraints
- **Choosing a 3D grid means deciding the following points:**
  - Grid dimension (number of cells)
  - Grid orientation
  - Grid block size

Grid size selection

- **Wells are generally considered in the center of cells**
- **Leave a few cells between wells (at least 2)**
- **Avoid large size variations between cells: ratio 2**
- **Limit the number of cells:**
  - Matrix size f(number of cells)2
  - Linear system solution 30 – 50 % of CPU time
  - Time step decreases with cells size (stability criteria)
- **Grid system must be carefully selected at beginning of study**

Gridding

Constraints and factors

- **Increase of CPU time with active cells**
- **Orientation**
- **Geometry / Geologic boundaries:**
  - Faults
  - Horizontal barriers
  - External limits
- **Avoid large size variations between cells: ratio 2**
- **Cell sizes: shape ratio and progression ratio**

Active and dead cells

- **Dead Cells**
  - Their porous volume is 0
  - Off-reservoir cells, allowing to represent a reservoir with an arbitrary form within a Cartesian geometry (parallelepiped)
  - → $Vp = (\Delta x * \Delta y * \Delta z * \phi * Hu/Ht) * MULPV$
- **Active Cells**
  - Their porous volume is > 0
- **Desactive cells with low Vp (<MinPoreV)**

Geological constraints

- **The grid orientation should be parallel to:**
  - The major faults direction, so that the grid block limits follow the fault trace. It produces a better representation of the transmissivity reductions if faults are present, with partial or total sealing effect
  - The fracture direction, in order to represent the permeability anisotropy kx vs. ky
  - The direction of sediment supply, for a better representation of drain, or to align with the main axis of turbiditic supply

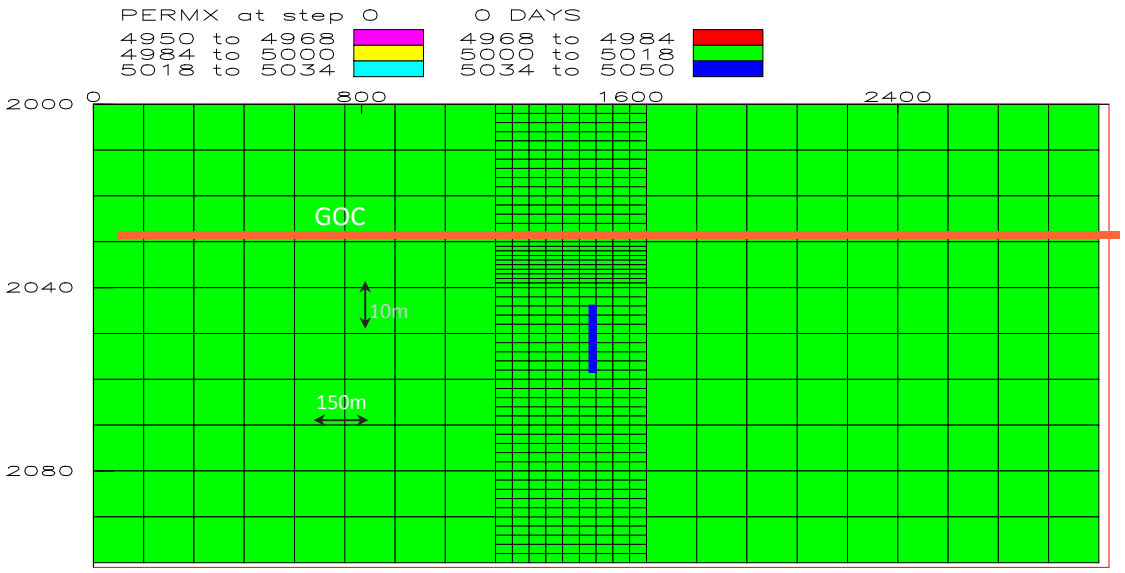
Choice of vertical discretization

- **Geological constraints: Good representation of the limits (layers, units), the barriers and the drains**
- **Dynamic constraints: Good representation of the displacement mechanisms:**
  - Fingering, gas tongue
  - Gravity drainage effect (segregation, gas injection)
  - Oil rim
- **Numerical constraints: fine discretization around wells:**
  - Good representation of well completions
  - Coning
  - Horizontal well
- **Alternative solution: LGR (Local Grid Refinement)**

Vertical discretization

- **If it appears necessary to refine in "Z" geological layers:**
  - Anticipate it as much as possible with the geologists before grid construction
  - In the other case, work with the geologist, in order to introduce the corresponding heterogeneities
  - Check if the given kz data are intrinsic

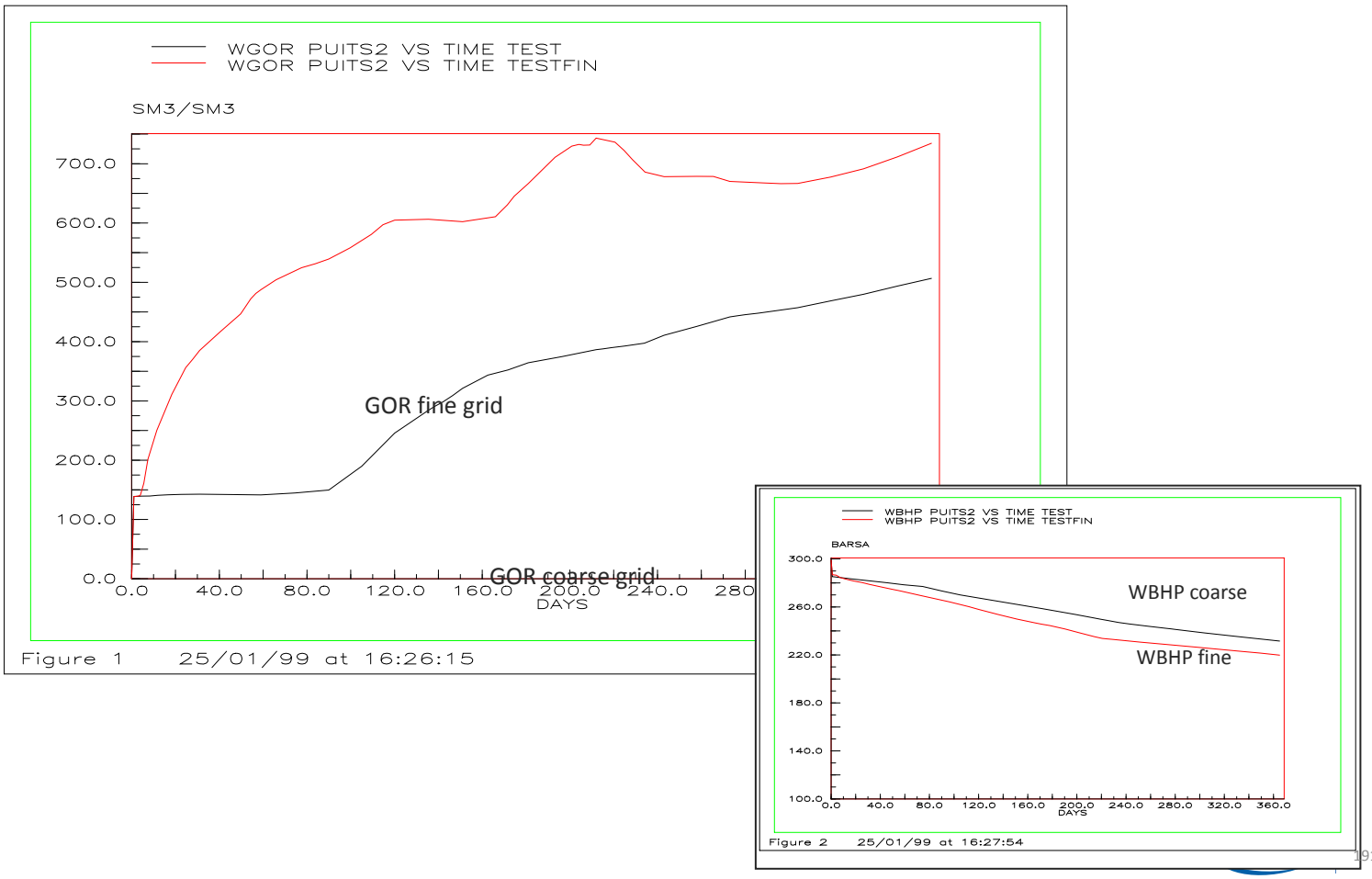
Using LGR to model gas coning



Kx=Ky=Kz=5000 mD

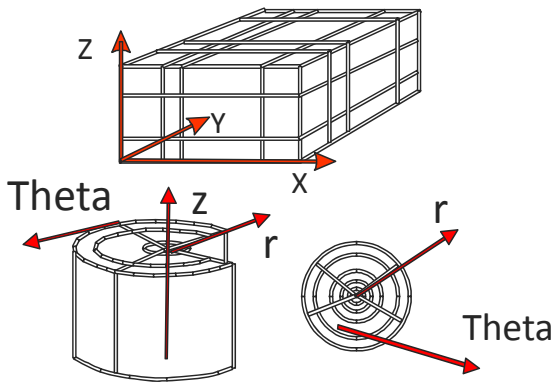
Qo = 6000 m^3/j

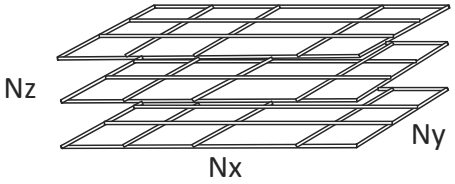
Gas Coning: grid influence on GOR

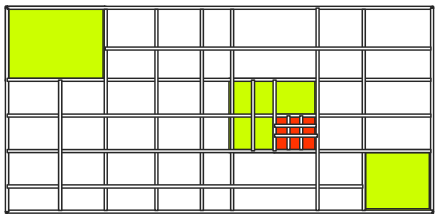


Grid geometry

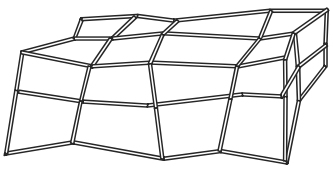
Cartesian grid







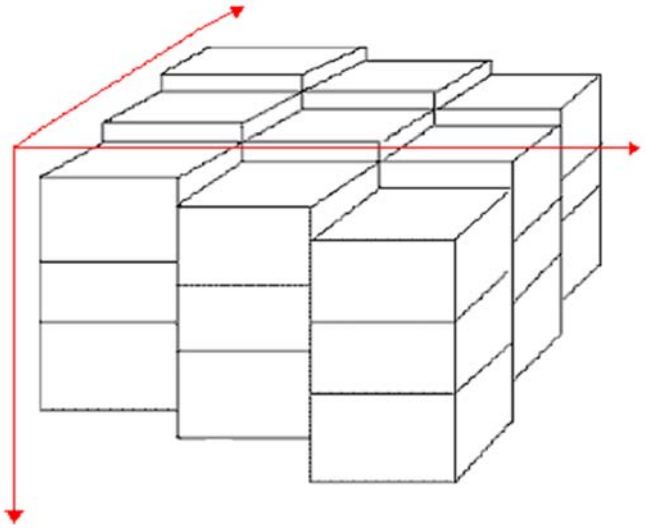
Sub-Gridding or LGR



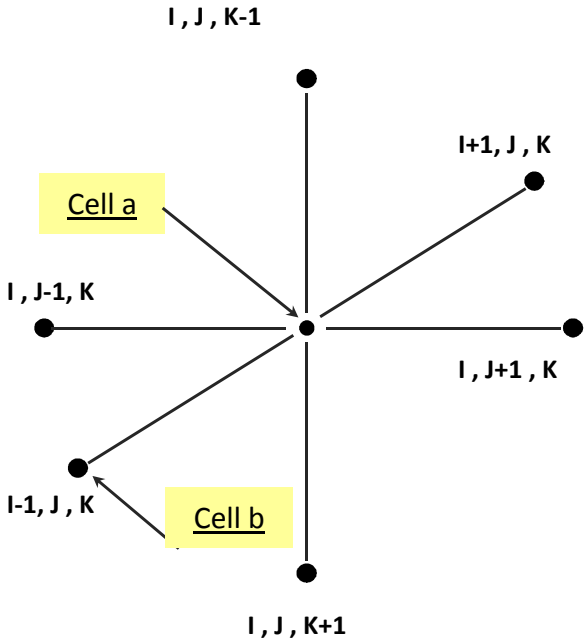
Non Orthogonal

Space discretization: sugar box geometry

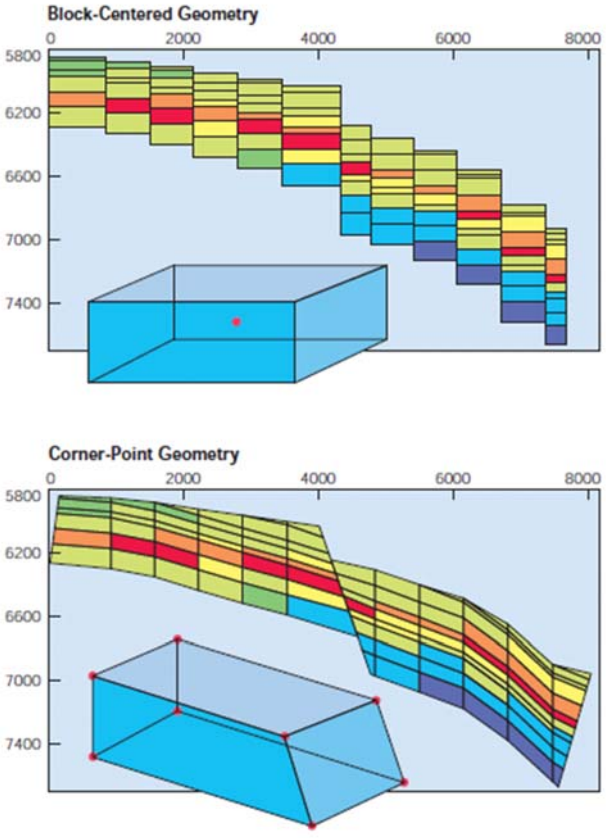
3 main flow directions



1 cell can communicate with 6 neighbours



Spatial discretization: Gridding - Geometry

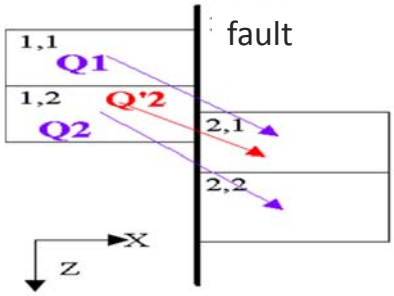


- Block centered geometry features flat-topped rectangular blocks that match the mathematical models behind the simulator.
- Corner point geometry modifies the rectilinear grid so that it conforms to important reservoir boundaries.
- Three dimensional grids are constructed from a 2D grid by laying it on the top surface of the reservoir and projecting the grid vertically or along fault planes onto lower layers.

Gordon Adamson et al.,
Oilfield Review, SLB. Summer 1996

Block-centered grid

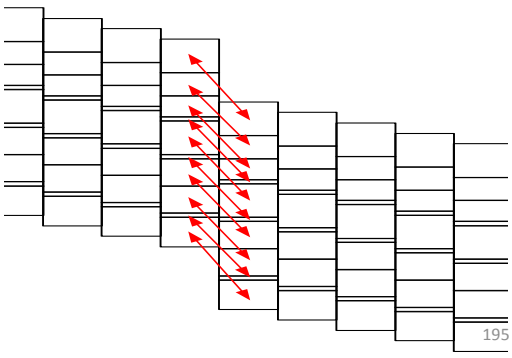
- Ease of use, no need for a grid builder
- Traditionnally link to finite difference scheme
- Poor description of complex geometry
- Mainly reserved to phenomenological model
- Physical connection between cells must be specified
- No difference between dip or fault (physical flow not always respected between numerically neighboring cells):



$$Q_1 = \frac{T_{1,1}}{\mu}(P_{2,1} - P_{1,1})$$

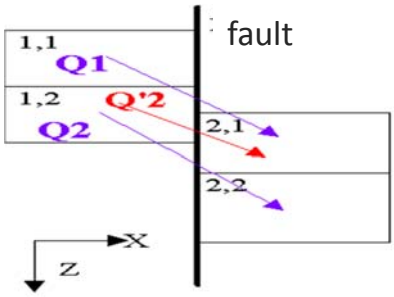
$$Q_2 = \frac{T_{1,2}}{\mu}(P_{2,2} - P_{1,2})$$

$$Q_2^{'} = 0$$



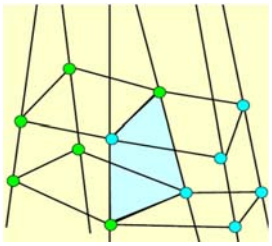
Corner point grid geometry

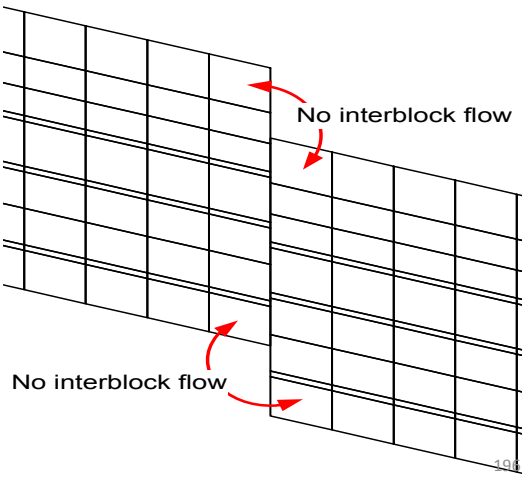
- Require a grid builder
- Difficult grid building step when converting a geological model to a reservoir grid model if a complex reservoir geometry
- NNC => irregular matrix system when cells are not orthogonal => require 2 pressures for flux computation otherwise numerical errors



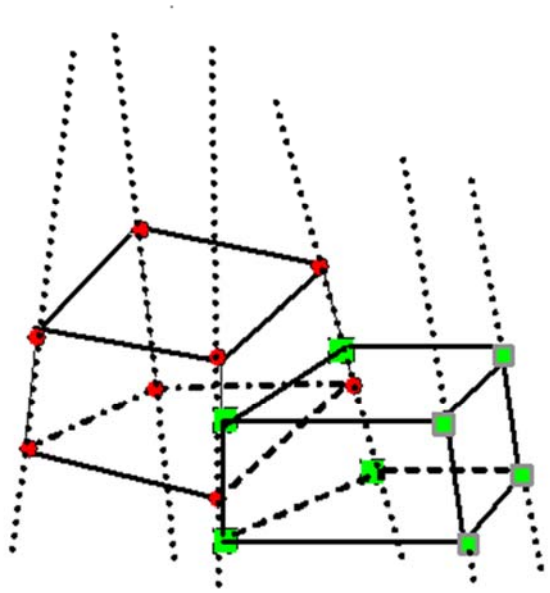
$$Q_1 = 0 \quad Q_2 = 0$$

$$Q'_2 = \frac{T'_{1,2}}{\mu}(P_{2,1} - P_{1,2})$$

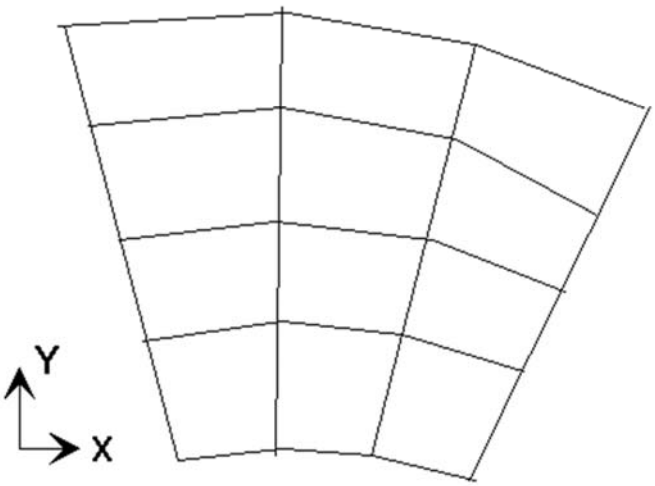




CPG grid



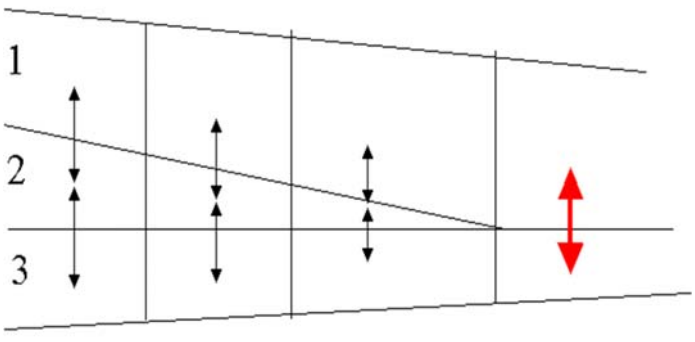
Align all corner on coordinate lines



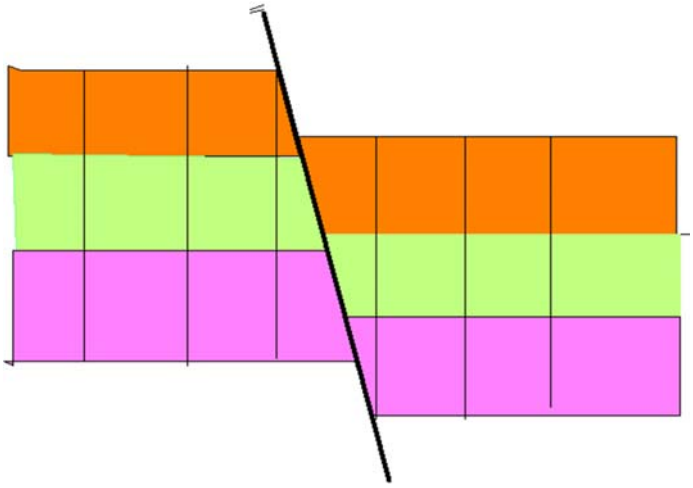
Curvilinear approximation

CPG grid features

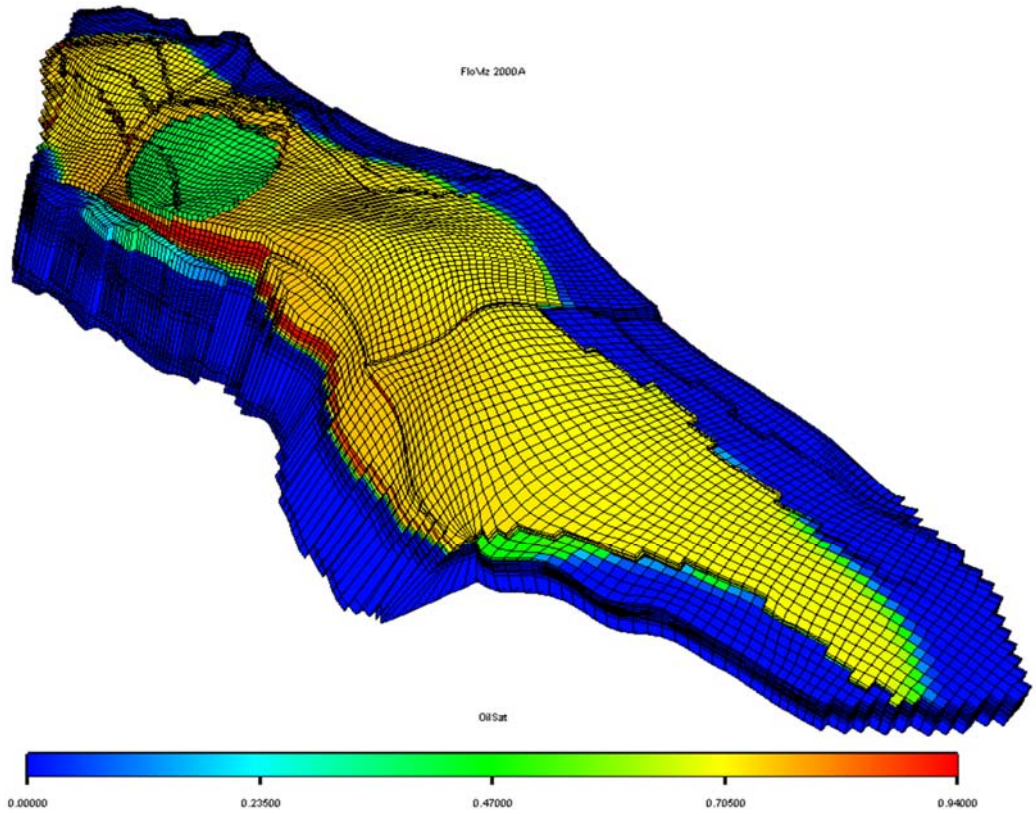
Pinch Out



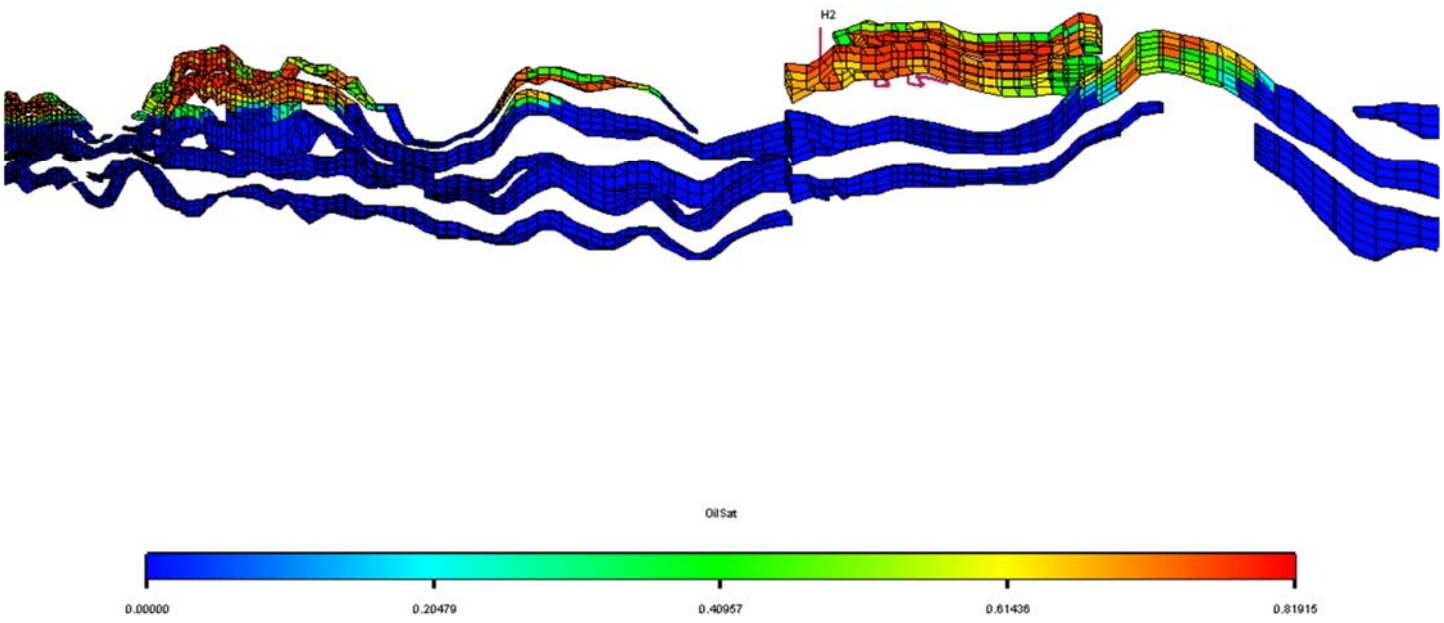
Tilted fault



Example of CPG reservoir model



Example of CPG reservoir model



Avantages of CPG grids

- **More flexible (8 independent nodes):**
- **In vertical direction:**
  - Dip description
  - Pinch-out modelling and tilted faults
- **In horizontal direction:**
  - Accurate Fault trace
  - One transmissivity multiplier per fault

- **Physical connections between cells with common surface area: pinch-out and large fault throw**

Draw back of CPG grid

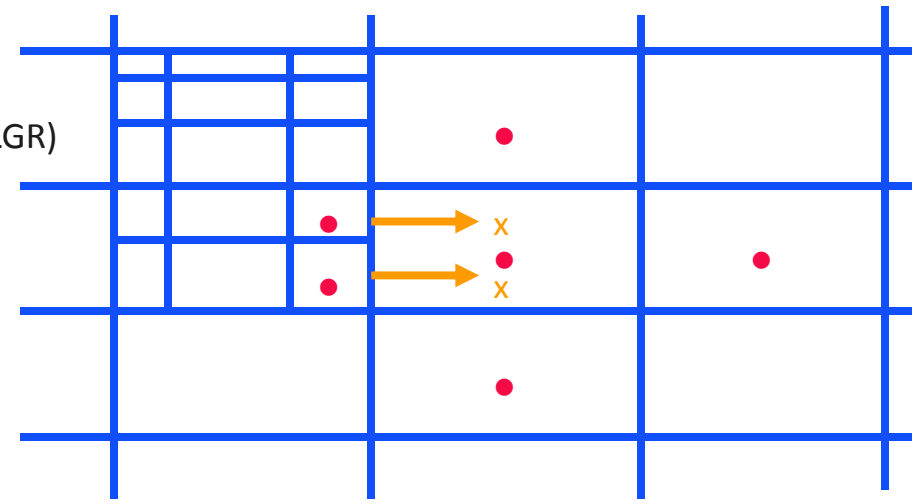
- **Needs a grid builder**

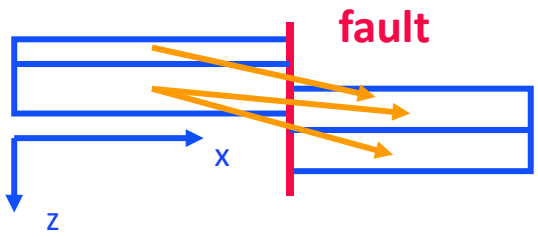
- **Difficult grid building step when converting a geological model to a reservoir grid model in a complex reservoir geometry situation**

- **NNC → irregular matrice system when cells are not orthogonal → require 2 pressures for flux computation otherwise numerical errors**

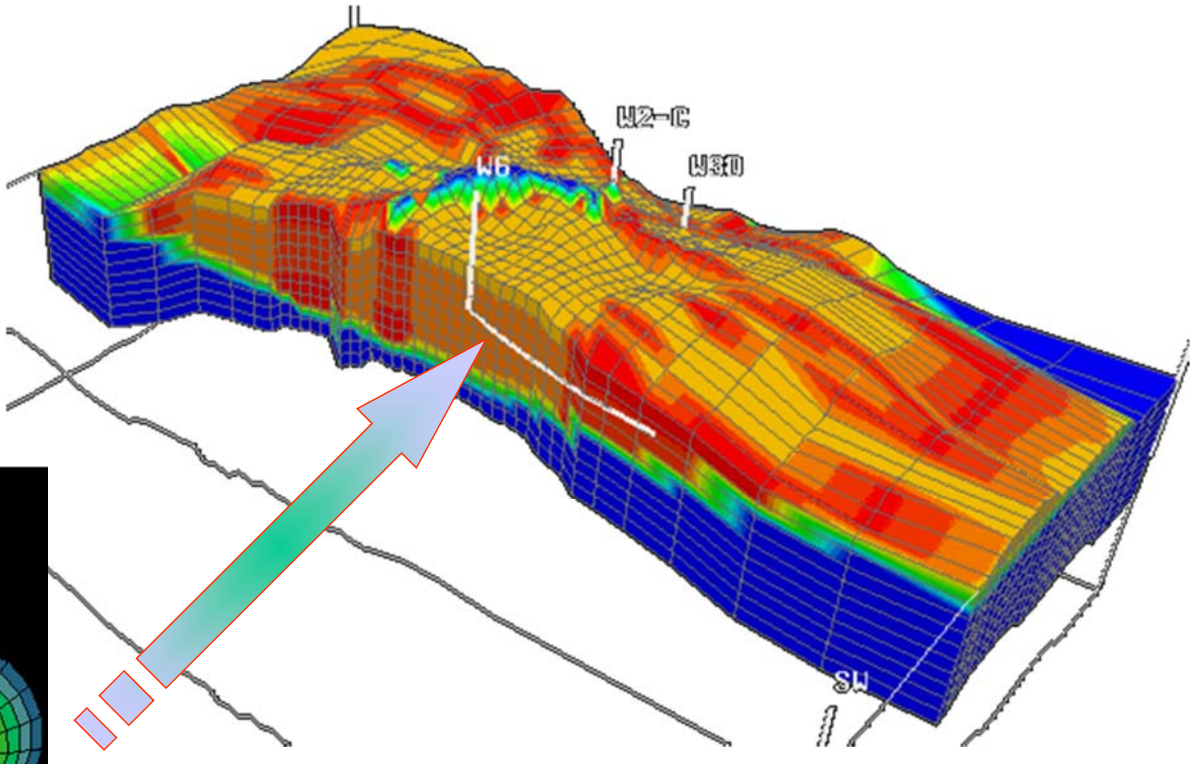
Complex connection scheme

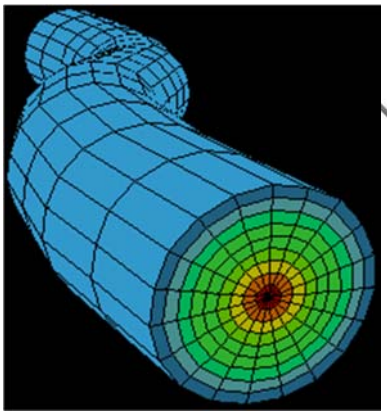
- **Required scheme if:**
  - Local Grid Refinement (LGR)
  - Fault with throw
  - Tetrahedron grid



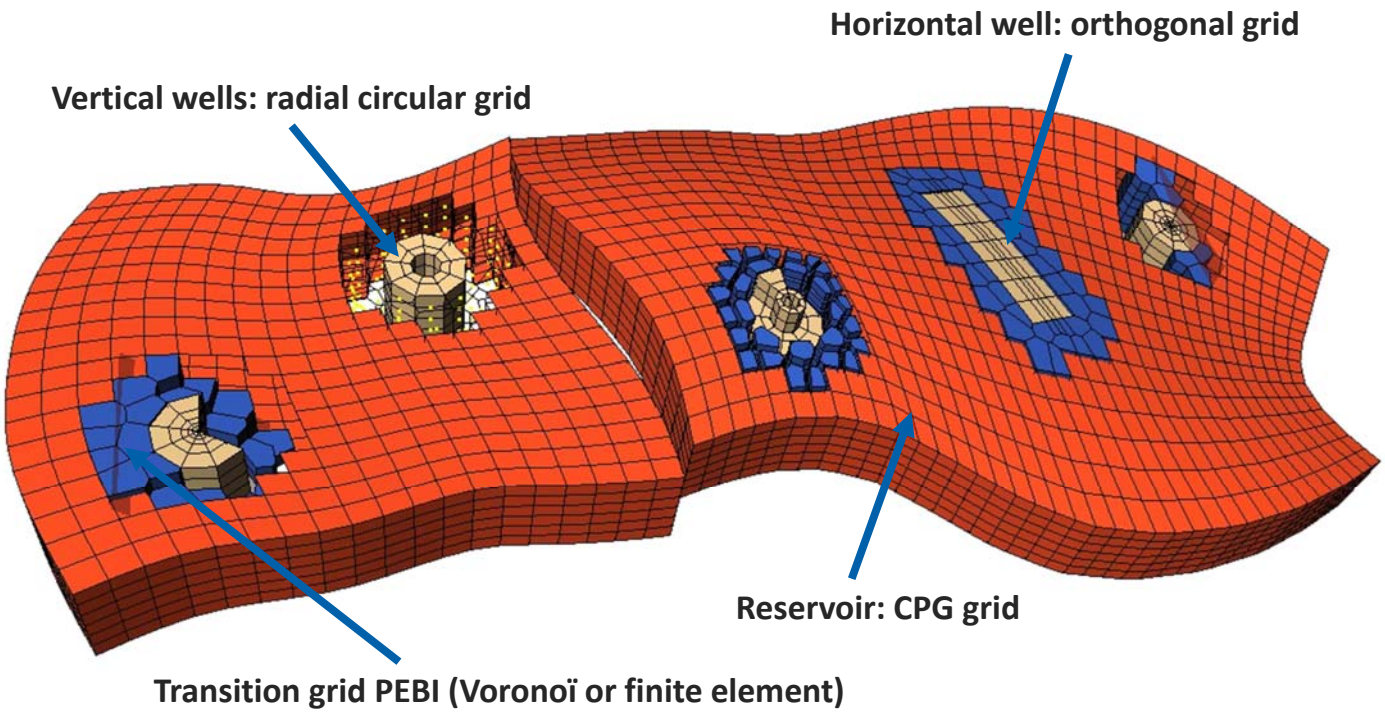


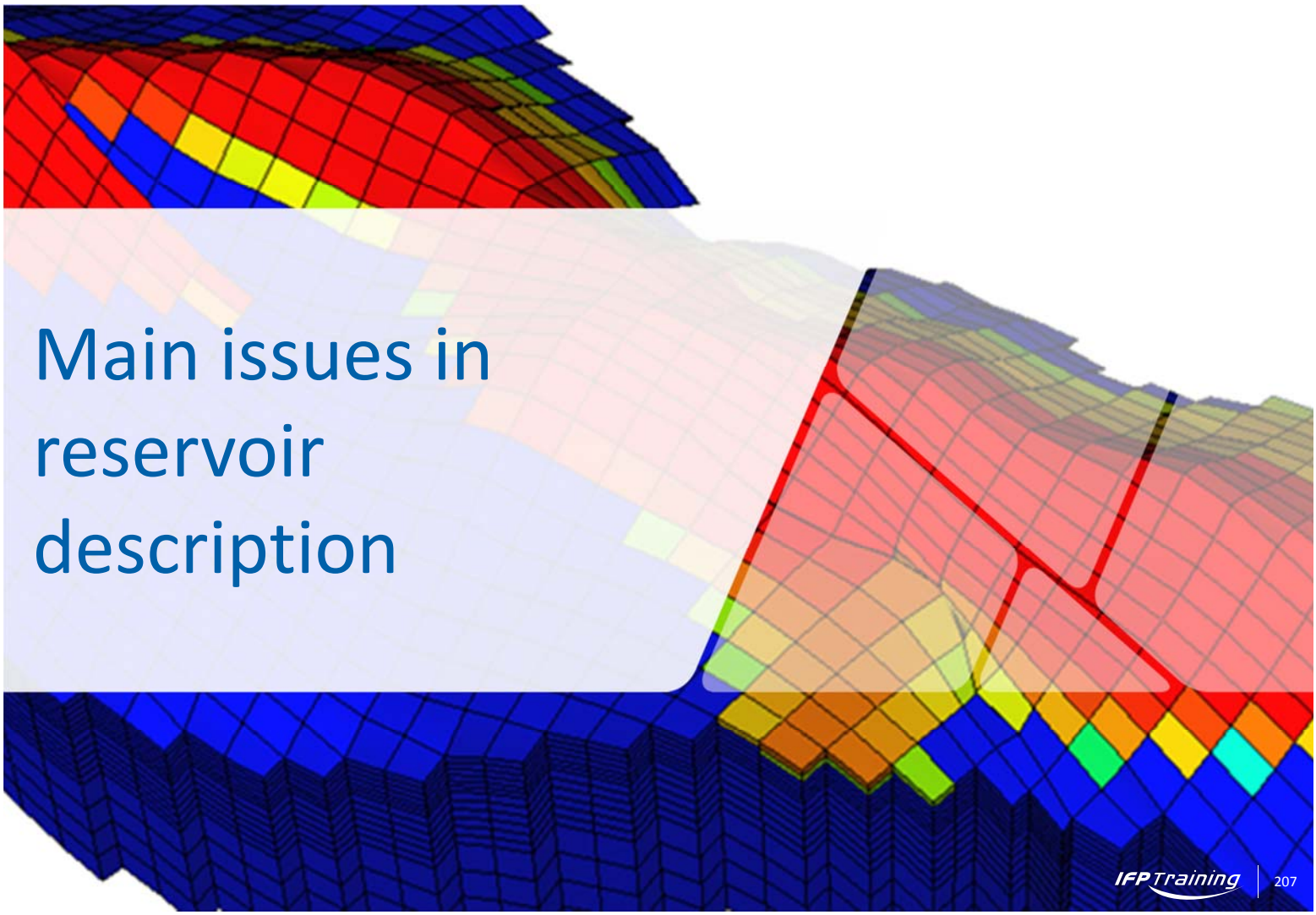
Flexible grid near wellbore





Hybrid grid


Horizontal well: orthogonal grid
Vertical wells: radial circular grid
Reservoir: CPG grid
Transition grid PEBI (Voronoï or finite element)

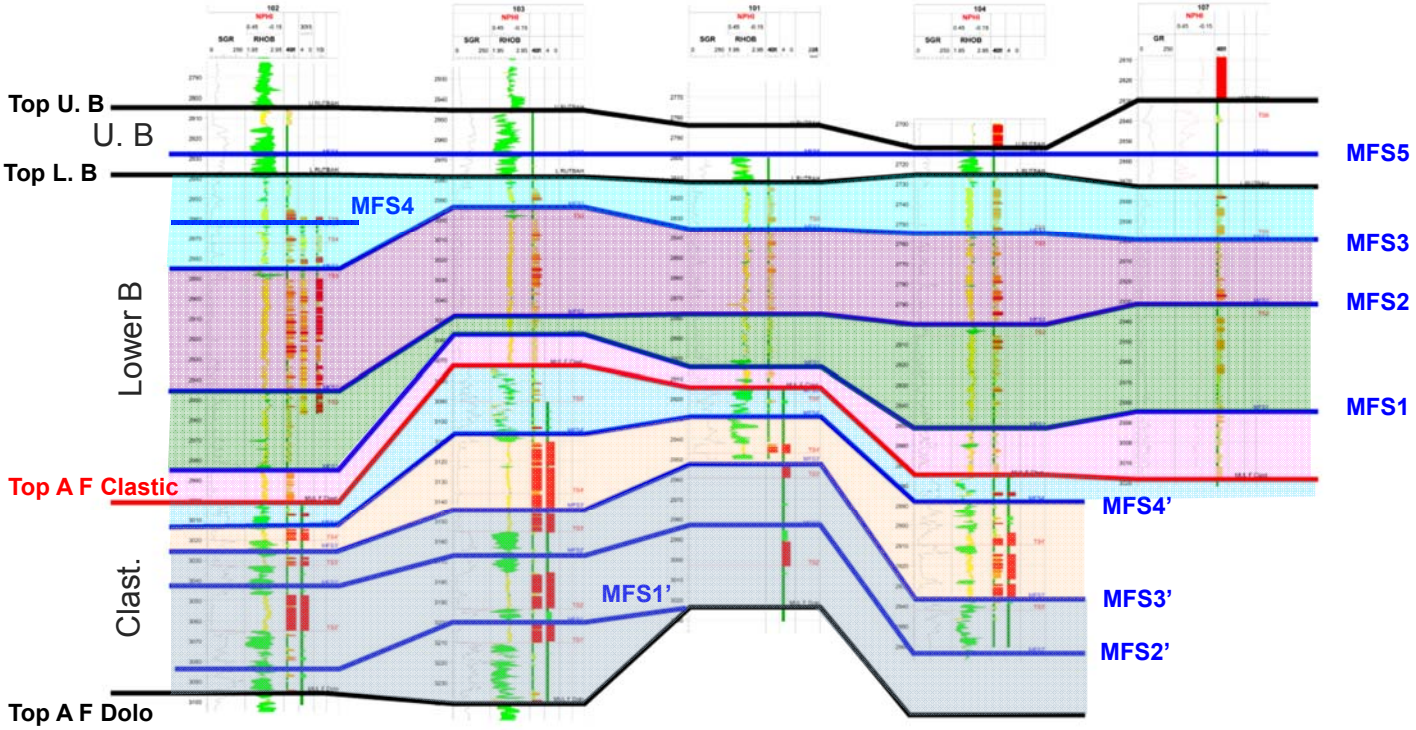


Main issues in reservoir description

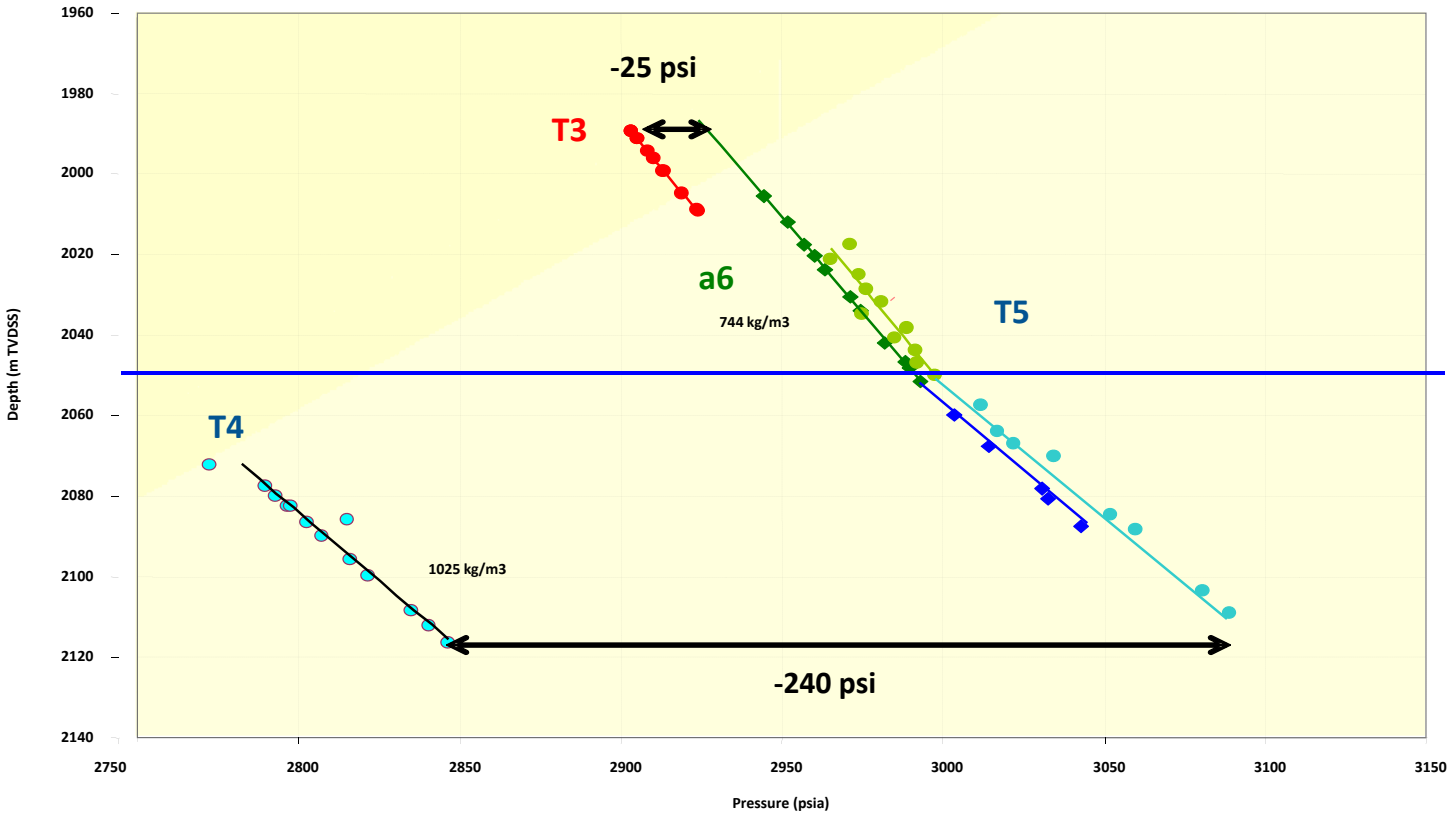
Reservoir description: main issues

- **Reservoir layering**
  - Identification of log correlations
  - Identification of flow units
- **Population of the petrophysical model**
  - Definition of Net to Gross, Porosity and Permeability per cell
  - Two main problems
    - Interpolate (or extrapolate) data in non recognised areas
    - Give an average for each parameter in each grid cell
- **Upscaling**
  - Reservoir engineering data are not constant in one grid cell
  - Hence the necessity for each parameter to precise:
    - The parameter distribution in one the grid cell
    - How to replace this distribution by one average value

Reservoir layering: use of log correlation



Reservoir layering: identification of flow units



Reservoir layering: non adjacent layers

- **It is possible to have non adjacent layers**

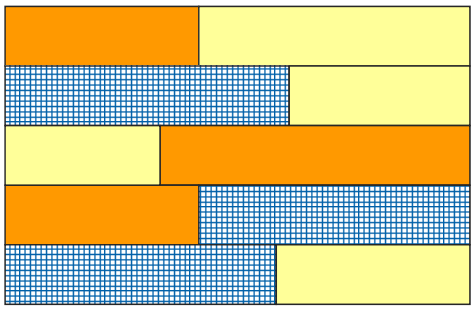
Reservoir 1 (Layer 1)

Inter reservoir (no layer)

Reservoir 2 (Layer 2)

- **This possibility can be used when**
  - There are interferences between the two layers
  - There is no oil displaced in the inter reservoir
  - Flows leaving one layer are identical to flows going into the other layer
- **Example: Permeable layers communicating through a water bearing low permeability layer**

Reservoir description: net thickness and porosity



Facies 1 (ϕ1, Vu1)

Facies 2 (ϕ2, Vu2)

Non reservoir

Cell Volume: $Vt = \Delta x \cdot \Delta y \cdot \Delta z$

Net Volume: $Vu = Vu1 + Vu2$

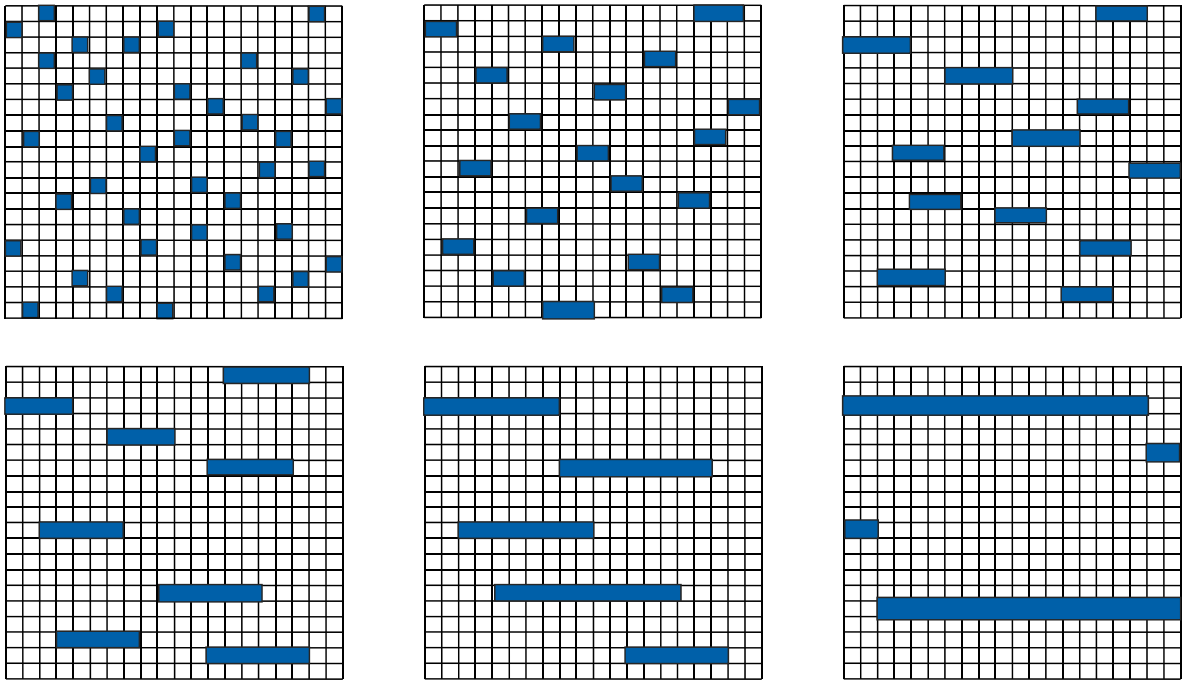
Porous Volume: $Vp = \phi 1 \cdot Vu1 + \phi 2 \cdot Vu2$

Net Thickness: $Hu = Ht \cdot Vu / Vt$

Porosity: $\phi = Vp / Vu$

Reservoir description: averaging data

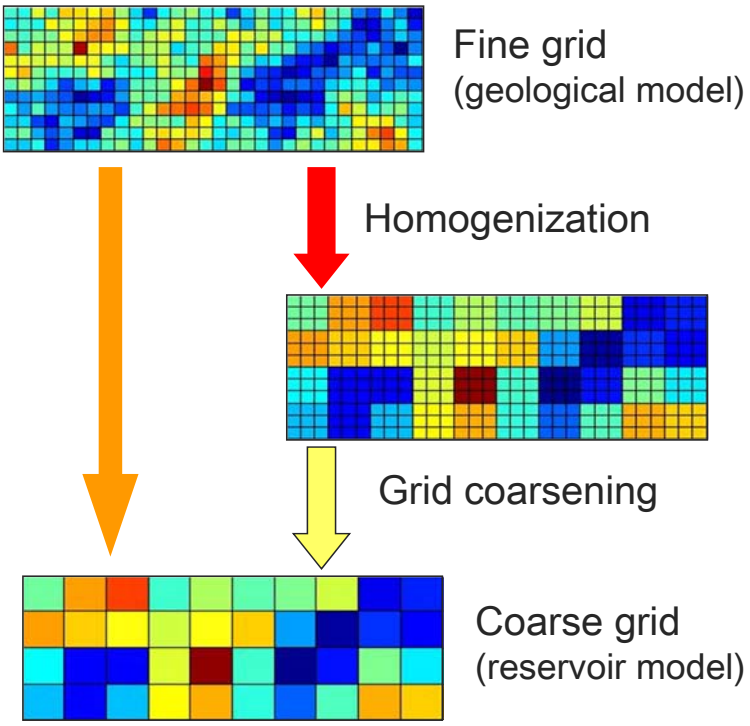
AVERAGE SHALINESS = 10%



Upscaling

- **Geological model contains a very large number of grid blocks. This level of resolution is generally incompatible with the computing capabilities of numerical flow simulators.**

- **To do so, fine grid blocks are grouped in aggregates: coarse grid blocks. The basic problem is to determine the equivalent properties of the coarse gridblocks.**



Upscaling: which property?

- **Additive variables: Swi, Sgc, ϕ, Vsh, NTG...**
  - Exact volume averages
- **Absolute permeabilities**
  - Analytical means: often used, but approximate
  - Numerical methods to minimize the loss of information
- **Relative permeabilities, capillary pressures and PI**
  - Not that easy, often disregarded
  - Numerical techniques

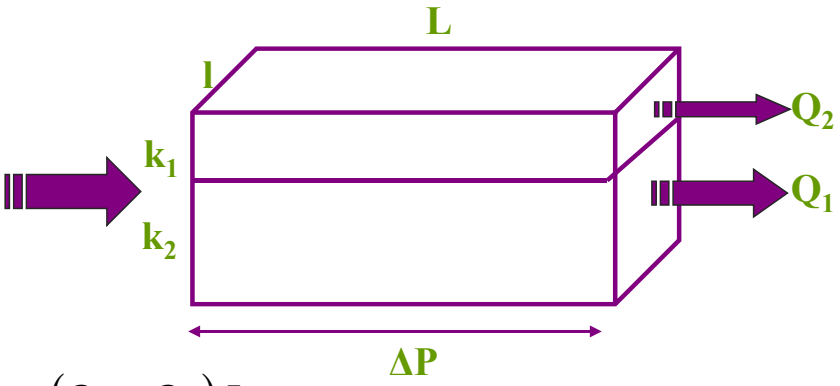
Permeability

- **The permeability is not a scalar, but rather a second order tensor.**
- **As permeability is not an additive property, Keq cannot be derived from a simple analytical formulation such as the arithmetic mean. Flow rate or dissipated energy must be considered instead:**
  - flow rates at the boundaries of the aggregate of fine gridblocks must be the same as those of the coarse gridblock.
  - dissipated energy must be identical for the aggregate of fine gridblocks and the corresponding coarse gridblock.

Algebraic methods: parallel flow

PARALLEL grouping

ΔP constant



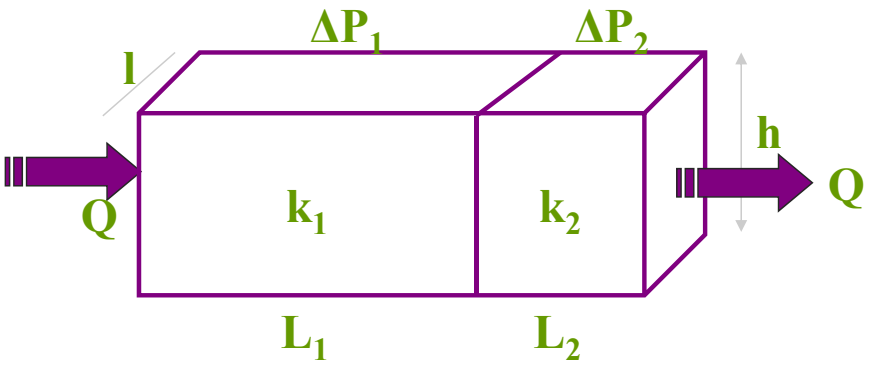
ΔP identical for the 2 layers

$$\Delta P = Q_1 \, L \frac{\mu}{l \, h_1 \, k_1} = Q_2 L \frac{\mu}{l \, h_2 k_2} = \frac{(Q_1 + Q_2) \, L \mu}{l \, (h_1 k_1 + h_2 k_2)}$$

Compute k_e to get Q with $\Delta Q_1 + \Delta Q_2$

$$\Delta P = (Q_1 + Q_2) \frac{L \, \mu}{l \, (h_1 + h_2) \, k_e} \quad \Rightarrow \quad k_e = \frac{h_1 k_1 + h_2 k_2}{h_1 + h_2}$$

Algebraic methods: serial flow



SERIES grouping

Q constant

Flow rate conservation

$$\Delta P_1 = \frac{Q \; L_1 \mu}{l \; h \; k_1}$$

$$\Delta P_2 = \frac{Q \; L_2 \mu}{l \; h \; k_2}$$

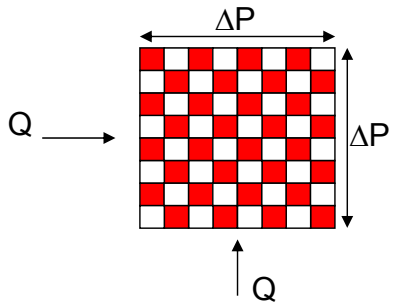
Compute k_e to get Q with $\Delta P_1 + \Delta P_2$

$$\Delta P = \frac{Q \, \mu}{l \, h} \left(\frac{L_1}{k_1} + \frac{L_2}{k_2} \right) = \frac{Q \, \mu}{l \, h} \frac{L_1 + L_2}{k_e} \quad \Rightarrow \quad k_e = \frac{L_1 + L_2}{\frac{L_1}{k_1} + \frac{L_2}{k_2}}$$

Harmonic average of permeability perpendicular to the flow direction

Algebraic methods: random isotropic flow

- **It is rigorous in the chess case, anisotropy:**



$$\ln(K_g) = \frac{1}{n}\sum \ln(K_i)$$

- **Mean of Cardwell & Parsons:**

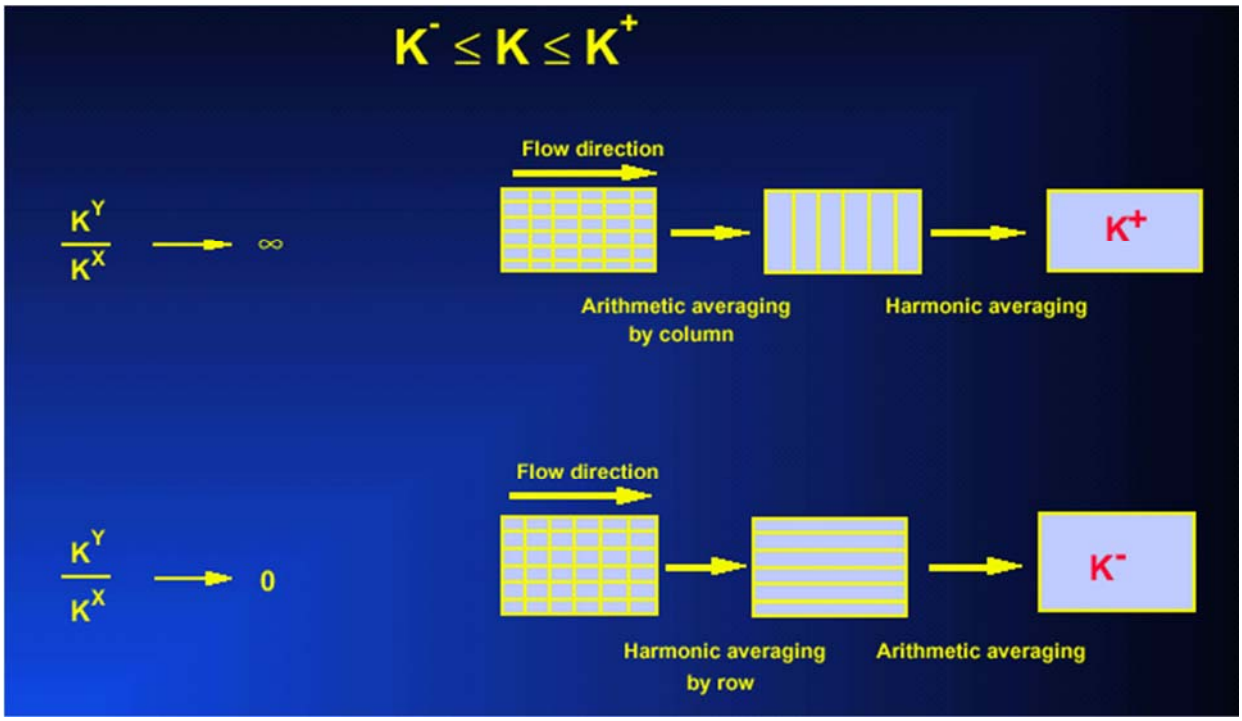
$$K^{CP} = \left(K^{CP,\min} \cdot K^{CP,\max}\right)^{1/2}$$

It can be shown that the Cardwell & Parsons mean bracket the equivalent permeability

$$K_h < K^{CP,\min} < K_{eq} < K^{CP,\max} < K_a$$

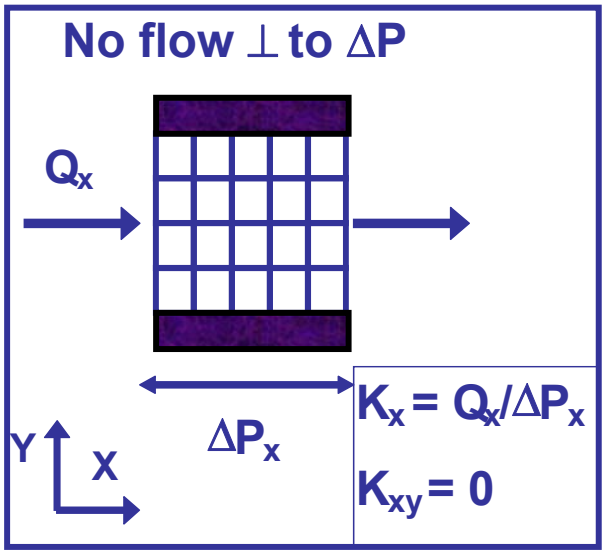
$K^{CP,\min}$: flow ∥ planes — $K^{CP,\max}$: flow ⊥ planes

Algebraic methods: Cardwell and Parsons

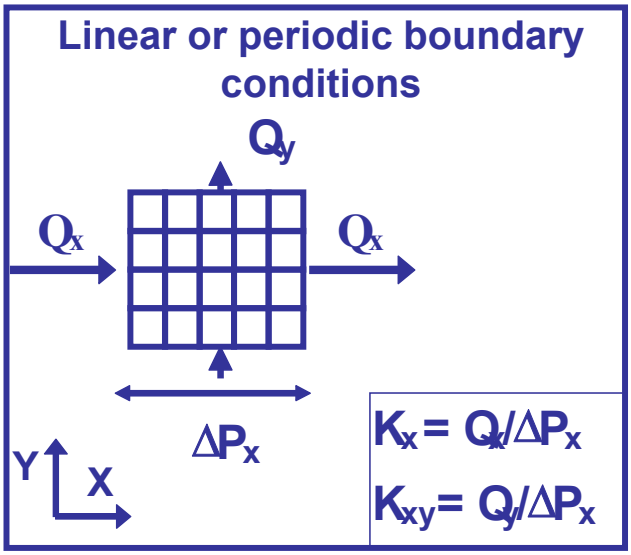


Flow based method

- Tensor:



Diagonal permeability tensor



Complete permeability tensor

Flow based method

- Numerical estimators differ from analytical methods by a need to solve the diffusivity equation:

$$div(k\nabla \cdot P) = 0$$

- for each coarse block, solve in each direction the pressure equation using finite element or volume technique, new techniques are proposed in order to capture the influence of the neighboring heterogeneities:

How to choose the aggregation rate?

- **Try to minimize the loss of information**
- **Do not include large drains or barriers in a coarse block: look at the facies proportion**
- **Compare permeability histograms**
- **Use single phase simulations**
  - Pressure field depletion
  - Production curves comparison
- **Keep enough grid blocks between injectors and producers to preserve breakthrough times.**

Modelling high perm streaks

- **Some reservoirs contain one to several high permeability streaks with order of magnitude higher permeability than average.**
- **Reservoir surveillance can successfully identify such streaks in reservoirs most seriously affected.**
- **Both static and dynamic models of affected reservoirs should reflect the existence of high permeability streaks.**
- **Technological challenge is to represent each and every high permeability streak identified in reservoir**

Key points to keep in mind

- **In a numerical model, space is discretized and the reservoir volume is described as a series of contiguous cells defined by a grid system**
- **The grid must take into account sedimentological and structural elements in order to explain reservoir anisotropy regarding fluid flow as well as dynamic information**
- **The gridding integrates reservoir geometry and petrophysical properties**
- **The grid orientation should be parallel to the major faults direction, so that the grid block limits follow the fault trace**
- **Grid geometry: cartesian, radial, non-orthogonal**
- **Grid types: Block centered, Corner point geometry (CPG), Hybrid**
- **Main issues in reservoir description:**
  - Layering
  - Properties distribution
  - Upscaling: aggregation rate and properties' averaging

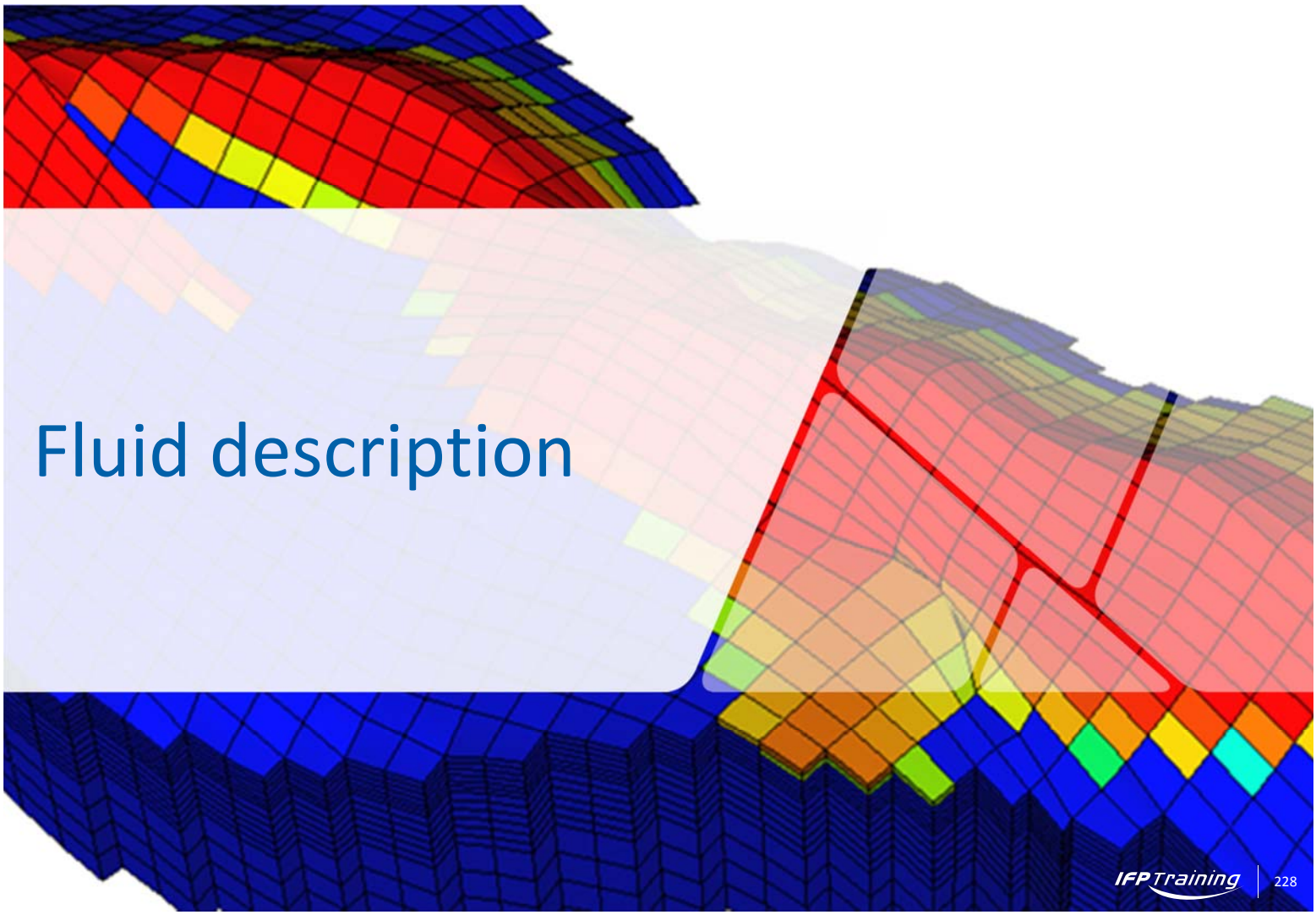


Dynamic reservoir simulation
Data review: PVT

IFP Training

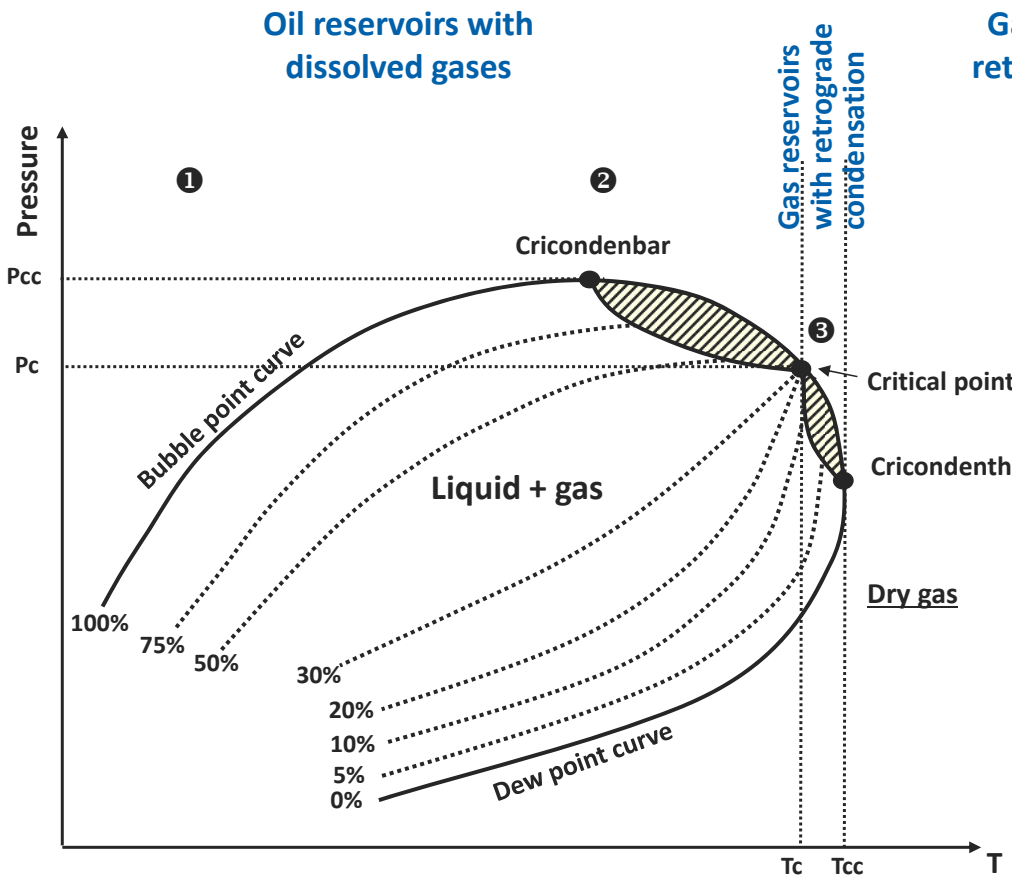
Sommaire

- Fluid description 228
- Black oil model 234
- PVT tests 250
- Compositional model 264
- PVT MODELING exercise 268



Fluid description

Phase envelope of a mixture



Zone ❶: No or poor contribution of dissolved gases

Zone ❷: Appreciable contribution of dissolved gases

Zone ❸: Retrograde with condensation of liquid in the reservoir

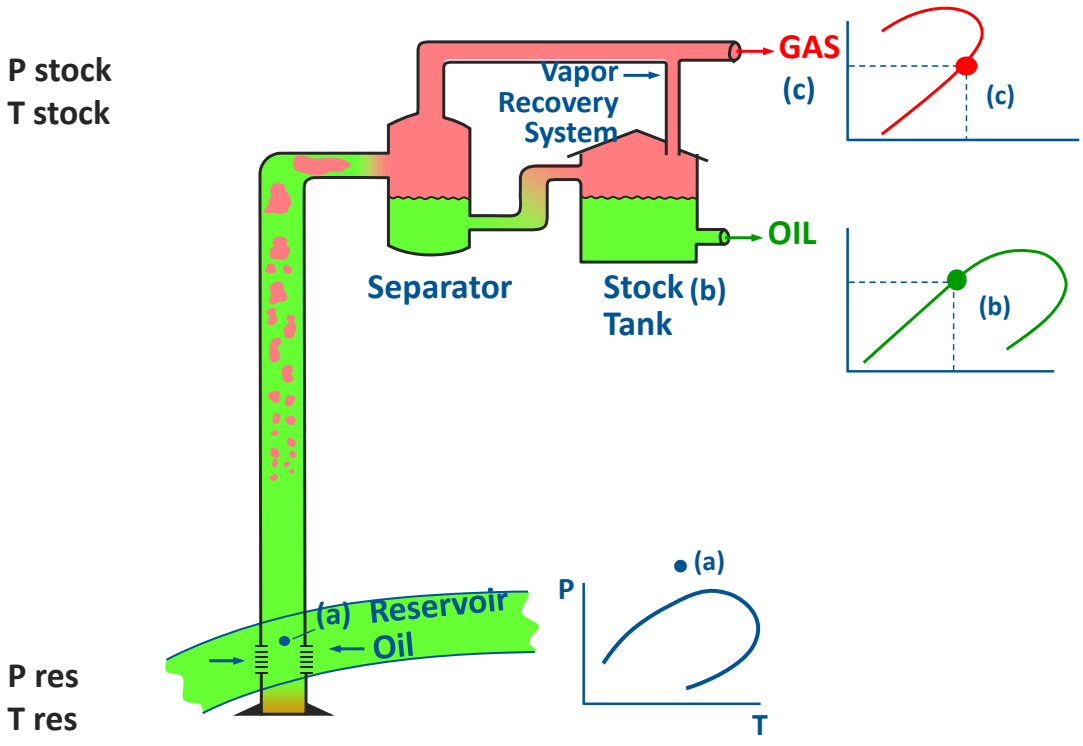
Zone ❹: Dry or wet gas

PVT data for numerical simulation

- **The PVT model describes:**
  - fluids (oil, gas, water)
    - densities
    - compressibilities
    - viscosities
  - phase equilibrium (between oil and gas generally)

- **The PVT model is chosen according:**
  - to the hydrocarbon type
    - heavy, medium oil
    - light oil, condensate retrograde gas
  - and the production mechanism
    - water injection, gas injection
    - miscible displacement

Hydrocarbons: surface & reservoir conditions



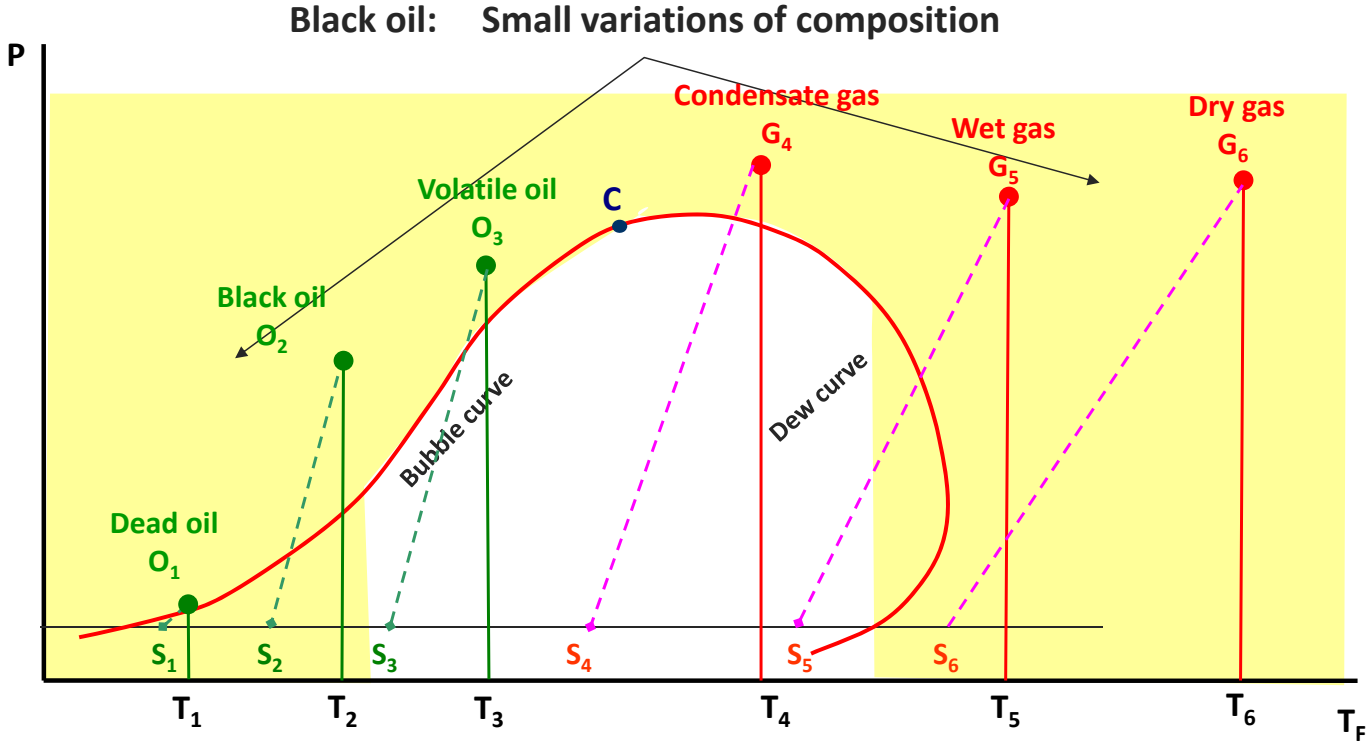
PVT data for numerical simulation

The two main PVT models are:

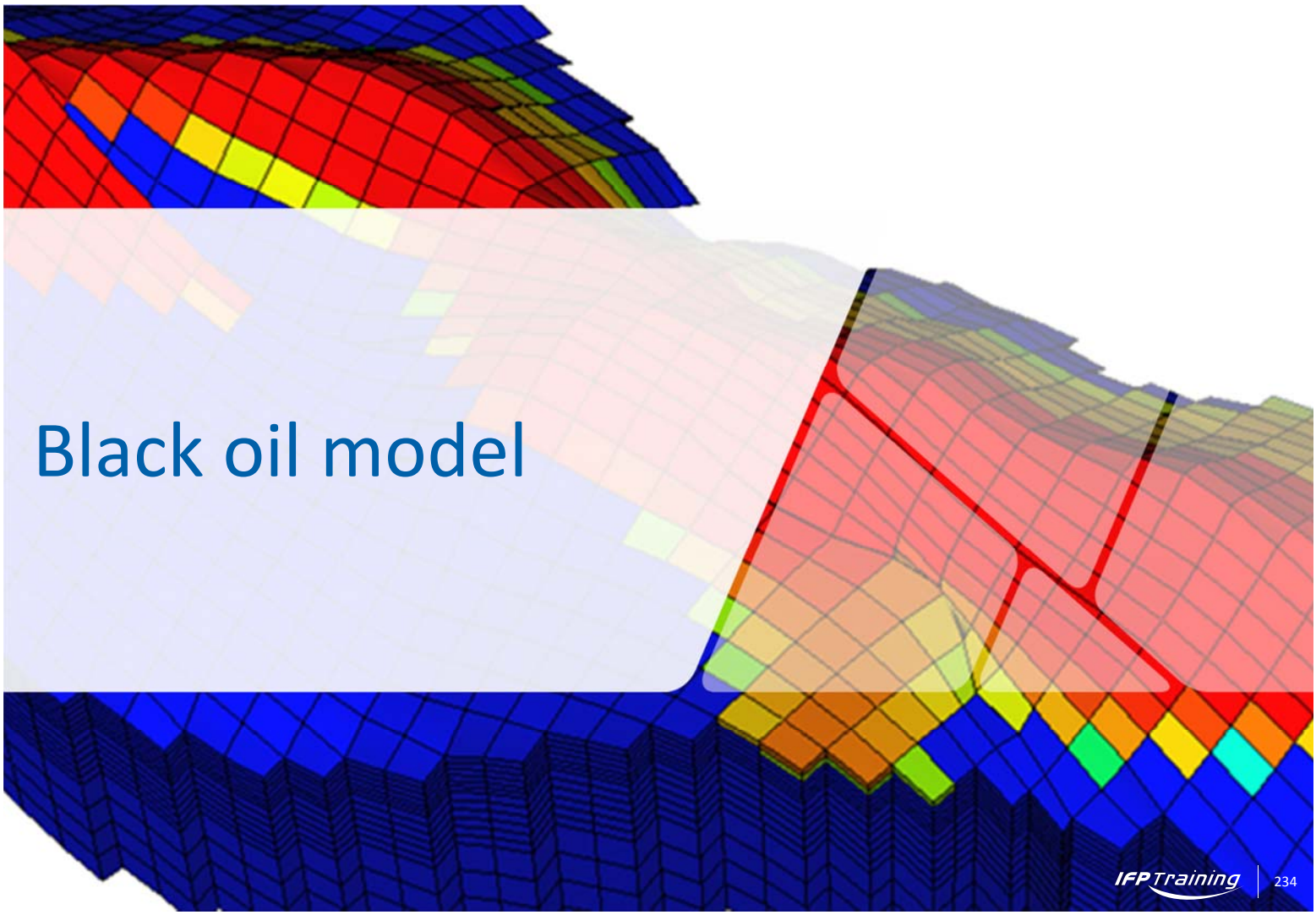
- **BLACK-OIL (improved BO, Bi-components)**
  - tabulated data
  - simplified PVT
  - for heavy - medium oil (Bo < 2), water injection, ...

- **COMPOSITIONAL**
  - Equation of State (EOS)
  - more and more precise and CPU consuming according to the number of components
  - for light oil (Bo > 2), retrograde condensate gas, miscible displacement, N2 or CO2 injection,...

Fluid description: influence of reservoir temperature

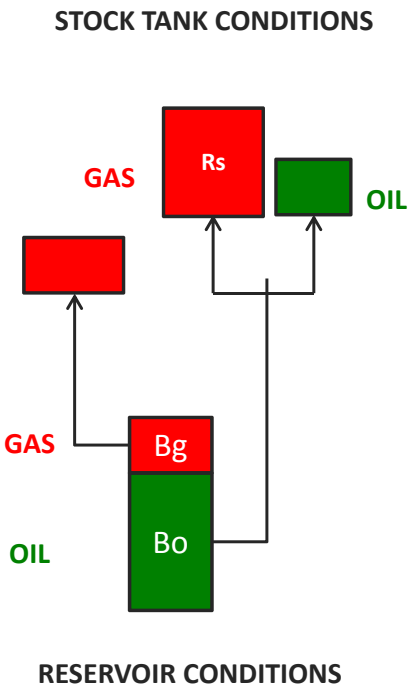


BLACK OIL MODEL: small variations of composition
COMPOSITIONAL MODEL: recomended near of critical point



Black Oil Model

- 3 phases: WATER, OIL, GAS
- 3 components: WATER, OIL, GAS
- Reservoir temperature is constant with time
- OIL and GAS in stock tank conditions have constant compositions
- OIL and GAS in reservoir conditions are mixtures of pseudo components OIL and GAS
- Volumes in reservoir conditions depends on pressure and concentrations



$$\rho_g = \frac{\rho_{gs}}{B_g} \qquad \rho_o = \frac{\rho_{os} + R_s \rho_{gs}}{B_o} \qquad C_{go} = \frac{R_s \rho_{gs}}{r_{os} + R_s \rho_{gs}} \qquad C_{oo} = \frac{\rho_{os}}{\rho_{os} + R_s \rho_{gs}}$$

Formation Volume Factor

$$Bo = \frac{\text{Volume of liquid in reservoir conditions}}{\text{Volume of liquid in stock tank conditions}}$$

Boi = Bob [1+Co(Pb - Pi)] for P >Pb

Bob = Boi [1+Co(Pi - Pb)] for P >Pb

$$Bg = \frac{\text{Volume of gas in reservoir conditions}}{\text{Volume of gas in stock tank conditions}}$$

$$GOR = \frac{\text{Volume of gas}}{\text{Volume of liquid}}$$

- - - - - - - - - -

$$API = \frac{141,5}{d} - 131,5 \quad (d = \text{oil density en g/cm3})$$

Solution gas/oil ratio (Rs)

- $Rs = \frac{V_{g\ std}}{V_{std\ ref}} = \frac{\text{Volume of gas in standard conditions}}{\text{Volume of oil in standard conditions}}$

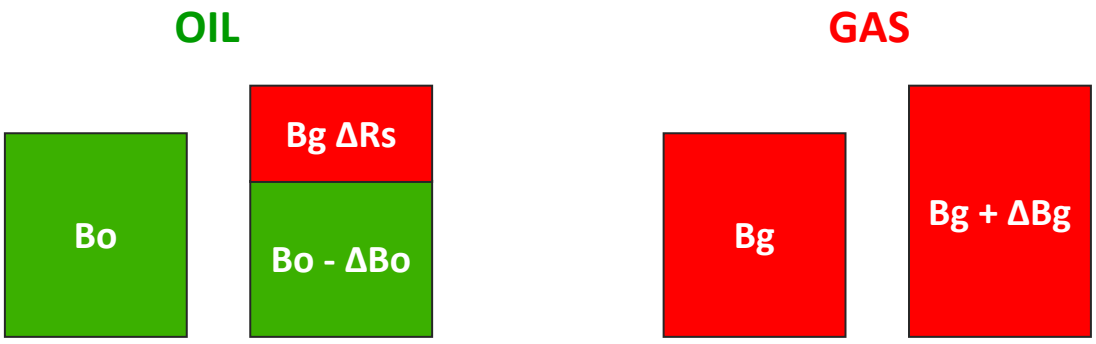
  Rs quantifies the amount of gaseous components which are dissolved in the oil at reservoir conditions.

Compressibility (Co)

- $Co = -\frac{1}{V}\left(\frac{\partial V}{\partial P}\right)_T = \frac{1}{Bo}\left(\frac{\partial Bo}{\partial P}\right)_T$

- Co quantifies the changes of oil volume during depletion at reservoir temperature, above the bubble point pressure.

Black oil: compressibility calculations



ΔVo = -ΔBo + Bg ΔRs

$$Co = -\frac{1}{Bo}\left(\frac{\Delta Bo}{\Delta P} - Bg\,\frac{\Delta Rs}{\Delta P}\right)$$

ΔVg = ΔBg

$$Cg = -\frac{1}{Bg}\,\frac{\Delta Bg}{\Delta P}$$

Main gas properties

Gas specific gravity

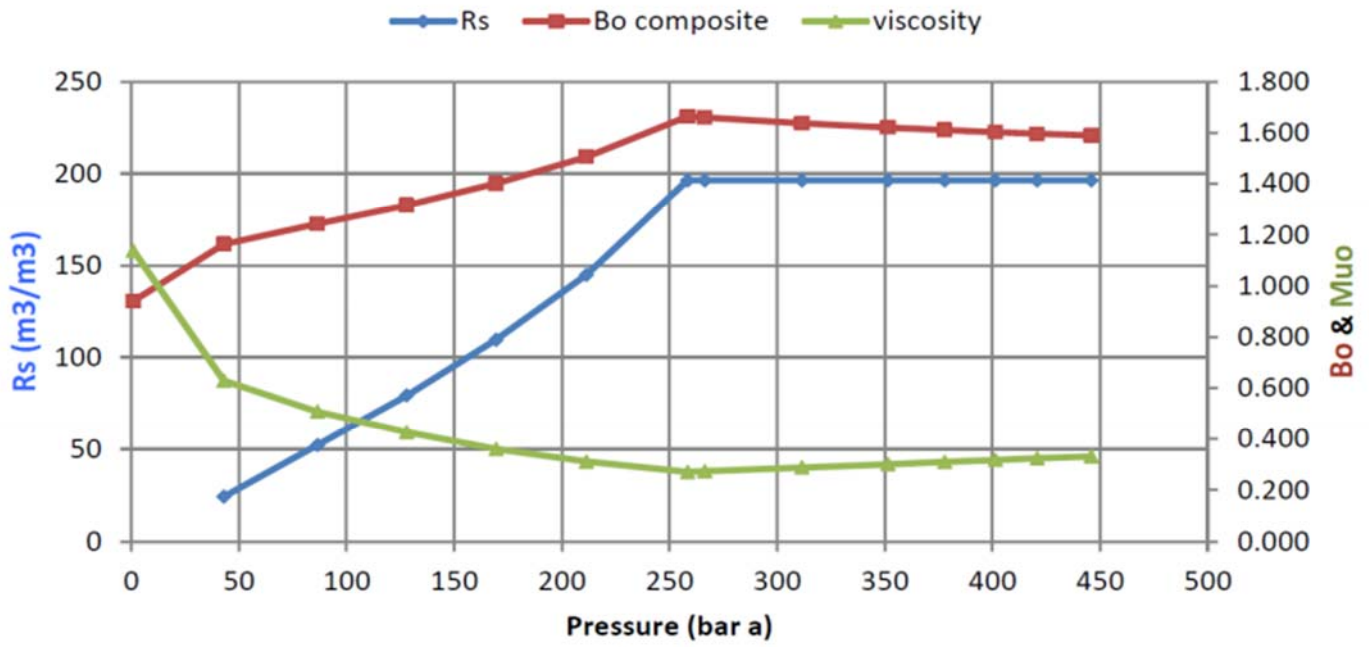
- **Gas specific gravity is the ratio of the gas density @ std. cond. to the air density @ std. cond.**
  Gas γ can be determined from the gas composition and Mw:
  - γ = (gas Mw)/(air/Mw) with Mw = 28.996 g/gmol @ 60°F, 1 atm)
- **Definitions for gas:**
  - Gas Specific Gravity: γ (air = 1) = $\rho_{gas}/\rho_{air} = Mw_{gas}/Mw_{air}$

    $\gamma = Mw_{gas}/28.978$
  - Gas density: $\rho_{gas} = Mw_{gas}/V_{air(molar)} = Mw_{gas}/23.645$

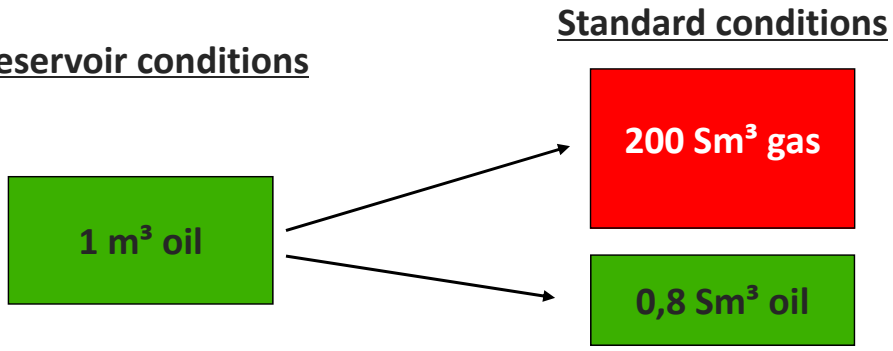
    $V_{air(1\ mole\ of\ air)} = 23.645$ $\rho_{gas} = \gamma * 1.225\ kg/m^3$
  - Air density: $Mw_{air} = 28.9784$ $\rho_{air} = 28.9784/23.645 = 1.225\ kg/m^3$

Black oil model

Typical behavior of oil properties



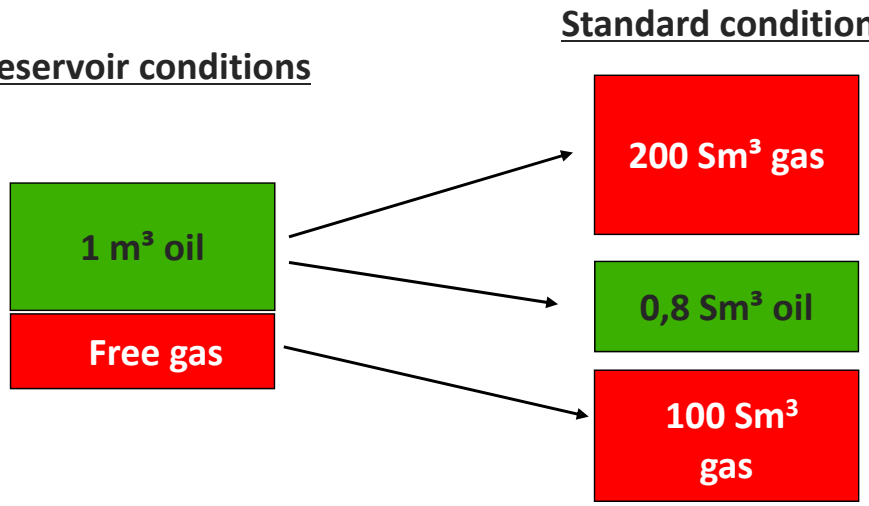
Oil properties – Solution GOR



Example:
Rs = 200/0.8 = 250 Sm3/Sm3

- **Solution GOR (Rs):**
  - Ratio between the volume of gas liberated at standard conditions and the volume of oil obtained at standard conditions
    Rs = Vg lib (Pstd,Tstd) / Voil (Pstd, Tstd)
  - Rs quantifies the amount of gaseous components which are dissolved in the reservoir oil.
  - Units: Sm^3/Sm^3, Scf/Stbbl
  - Typical values : 100 Sm^3/Sm^3 (black oil), 300 Sm^3/Sm^3 (light oil)

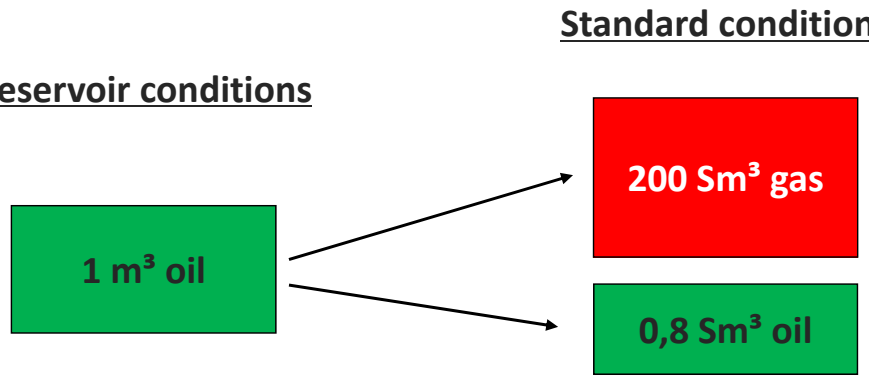
Oil properties – Production GOR



Example:
Production GOR = 300/0.8 = 375 Sm3/Sm3

- **Production GOR:**
  - Ratio between the volume of gas produced (liberated gas + free gas) at standard conditions and the volume of oil obtained at standard conditions
    GOR = (Vg lib (Pstd,Tstd) + Vg free (Pstd, Tstd)) / Voil (Pstd, Tstd)
  - Units: Sm^3/Sm^3, Scf/Stbbl
  - Production GOR ≥ Solution GOR

Oil properties – FVF



Example:
Bo = 1.0/0.8 = 1.25 v/v

- **Formation Volume Factor (FVF or Bo):**
  - Volume of oil at reservoir conditions (P,T) which must be produced to obtain 1 m^3 of oil at standard conditions
    Bo (P,T) = Voil (P, T) / Voil (Pstd, Tstd)
  - Units: v/v, m^3/Sm^3, bbl/Stbbl
  - Typical values: 1.25 v/v (black oil), 2.0 v/v (light oil)

$$Bo = \frac{\rho_g x R_s + \rho_{osT}}{\rho_{o(pT)}}$$

Fluid description: PVT Region

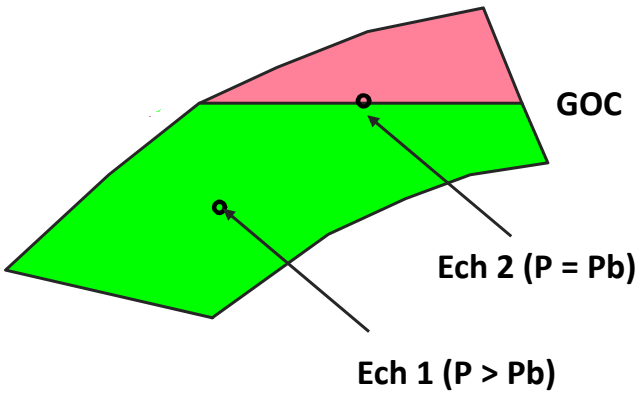
Constant Saturation Pressure

- All samples collected at initial state have the same saturation pressure
- Measurements of Bo(P), Rs(P), µo(P) for one sample give values of Bo, Rs, µo everywhere in the reservoir at anytime

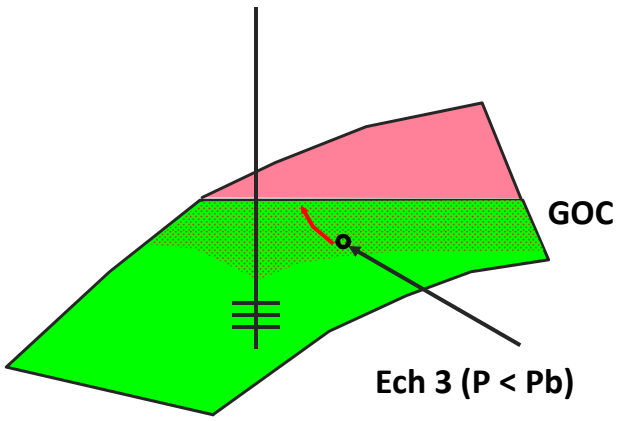
Variable Saturation Pressure

- All samples collected at initial state have a saturation pressure varying with an understandable law (e.g.: saturation pressure depends on depth)
- Measurements of Bo(P,Pb), Rs(P,Pb), µo(P,Pb) for one sample give values of Bo(Pb), Rs(Pb), µo(Pb) everywhere in the reservoir at anytime

PVT region: constant saturation pressure

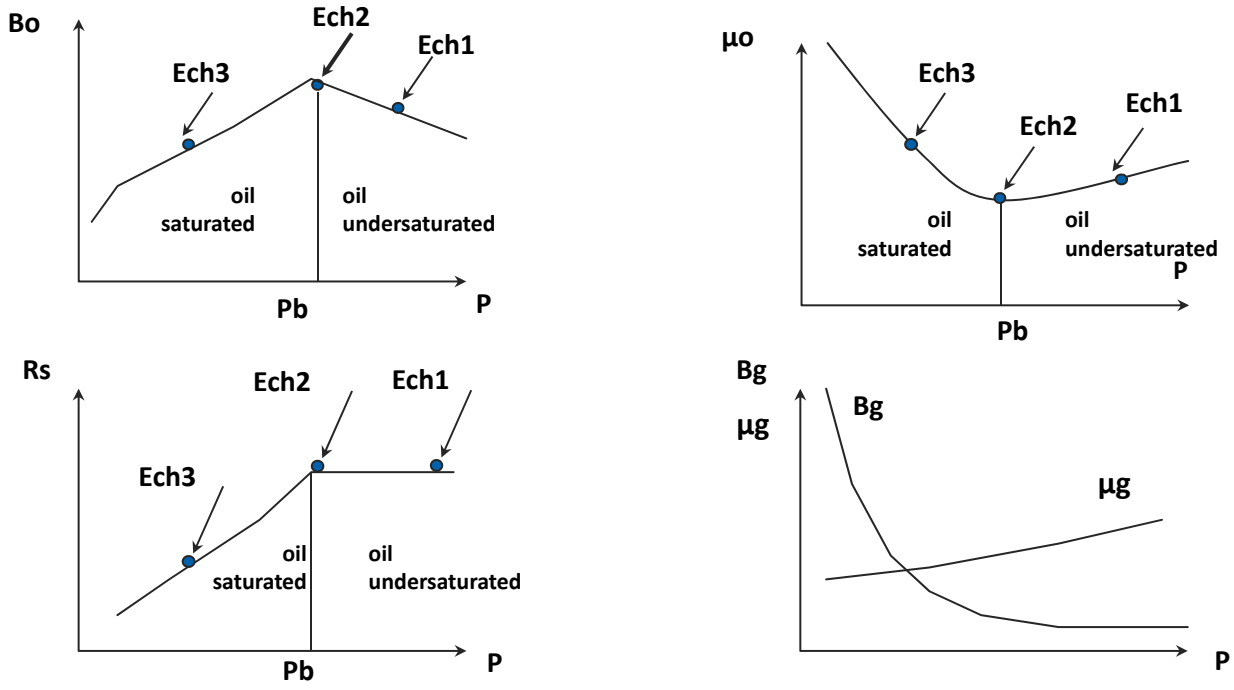


Initial state

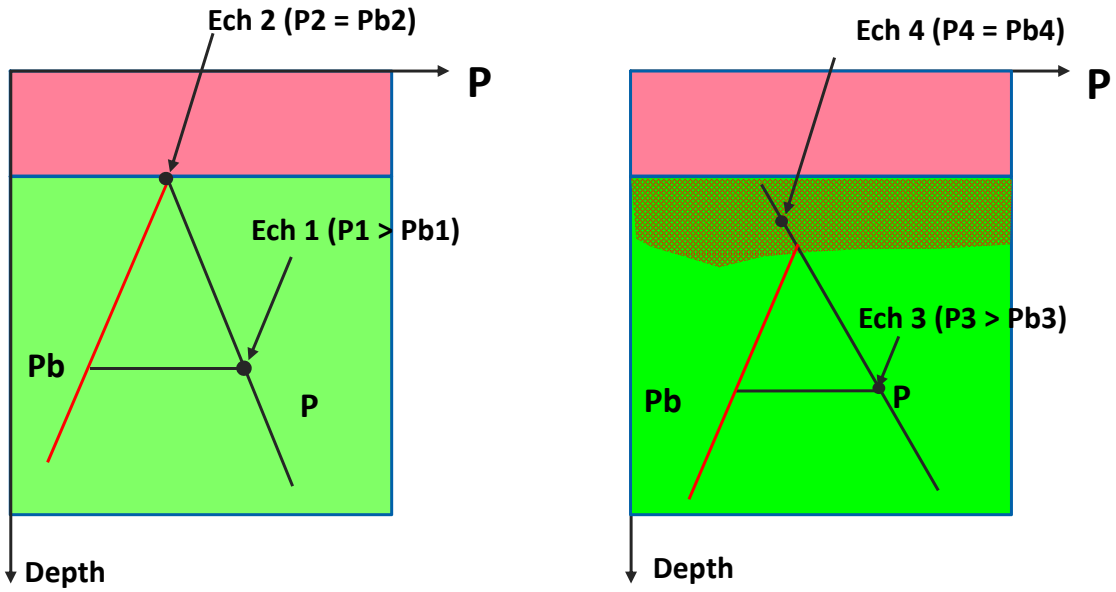


Depleted reservoir

PVT region: constant saturation pressure

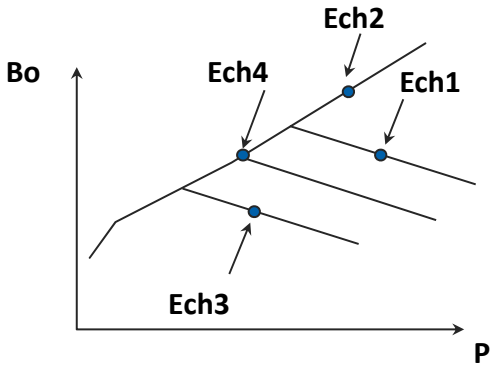


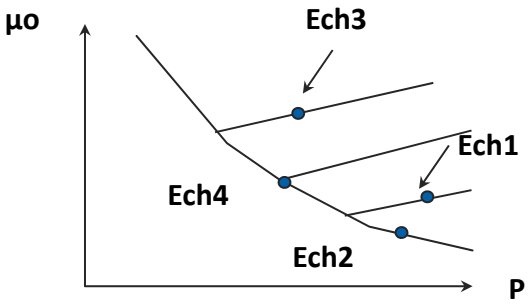
PVT region: variable saturation pressure

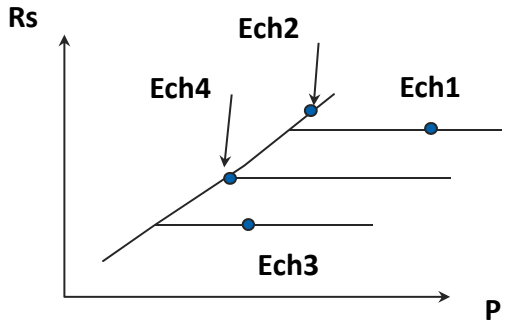


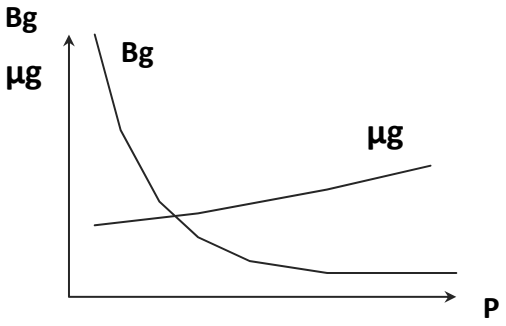
Initial state **Depleted reservoir**

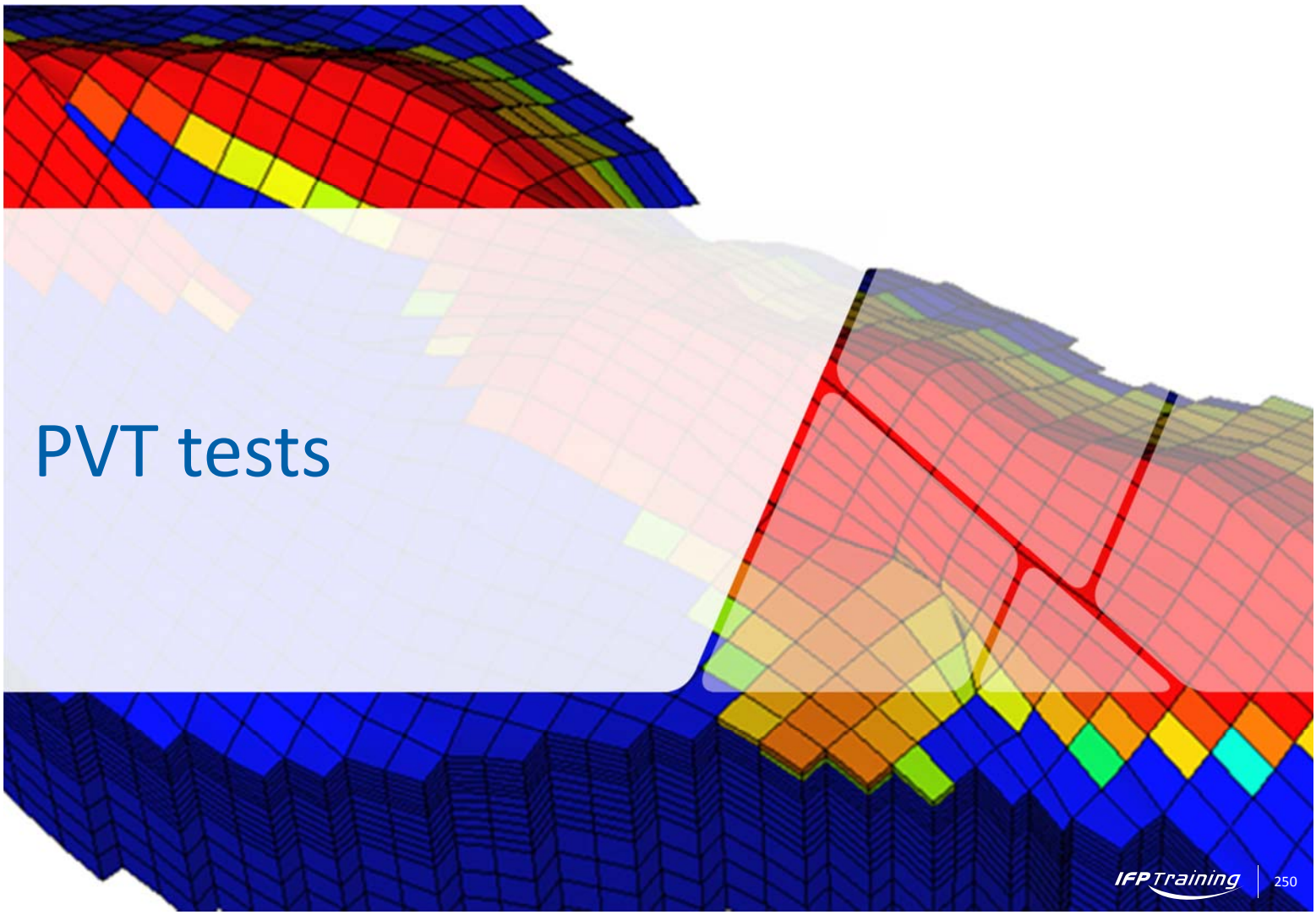
PVT region: variable saturation pressure







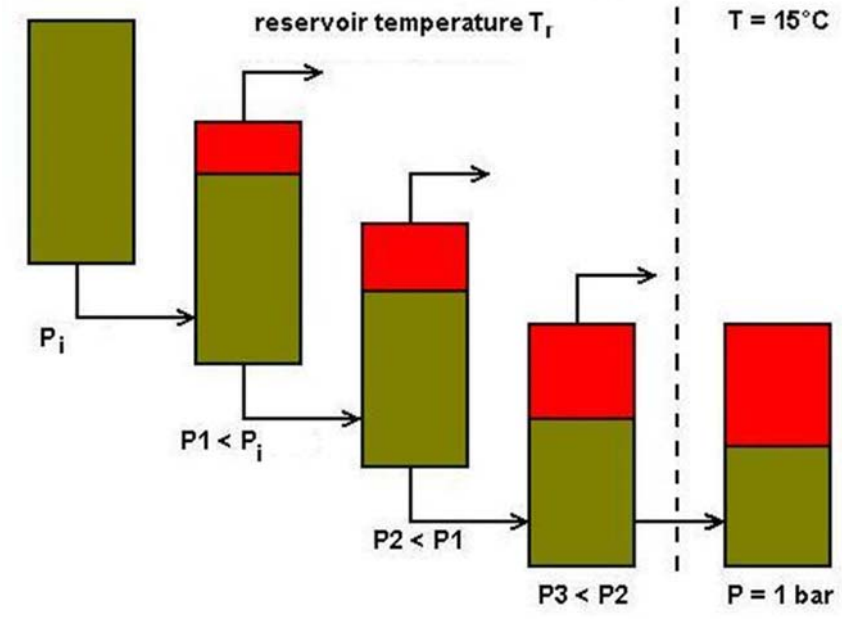


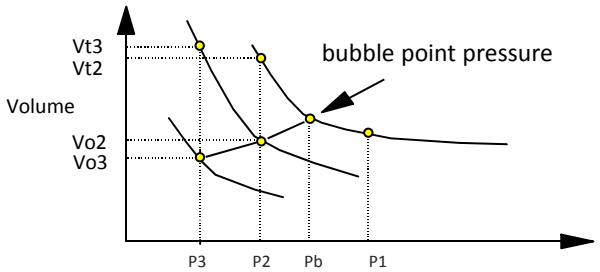


PVT tests

Oil PVT study – Differential liberation

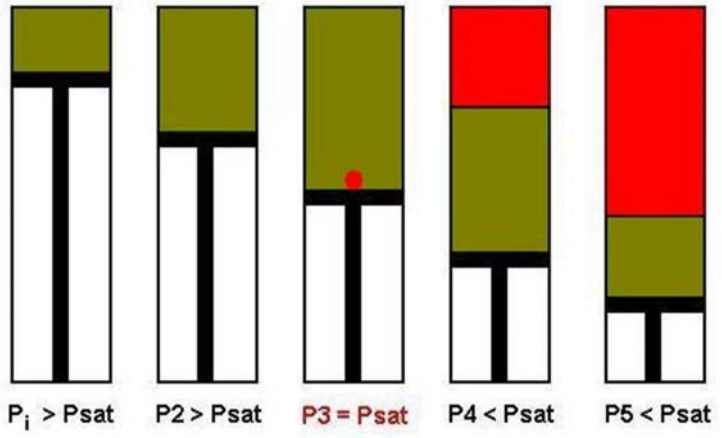
- **Determine:**
  - Bubble point pressure at reservoir temperature (Pb)
  - Amount of solution gas as a function of pressure
  - Liberated gas properties: compressibility, composition, density,Bg
  - Oil properties as a function of pressure: density, Bod, Bobd, Rsd,

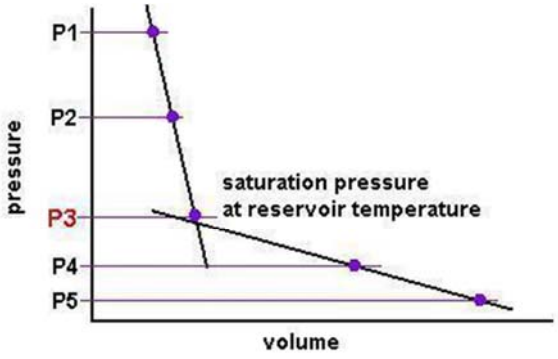




Oil PVT Study – Constant composition expansion

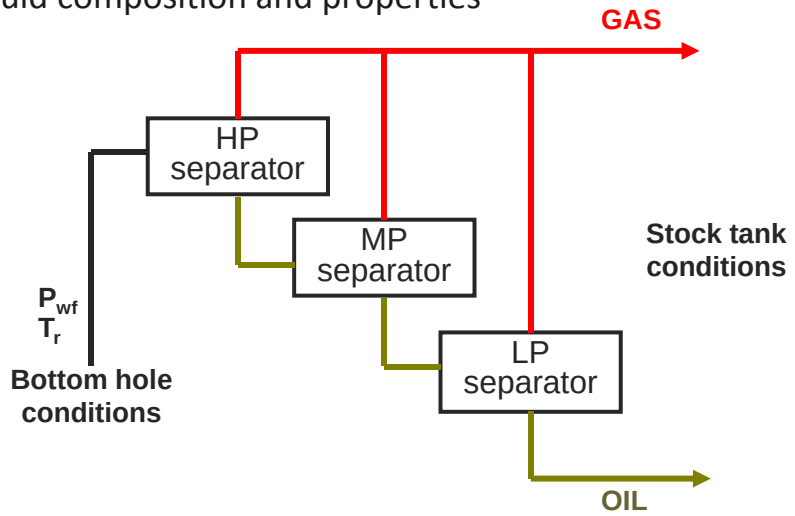
- **Determine:**
  - Bubble point pressure at reservoir temperature (Pb)
  - Isothermal compressibility factor of oil at bubble point (Co)
  - Gas compressibility factor (Z)
  - Global volume of oil as a function of pressure

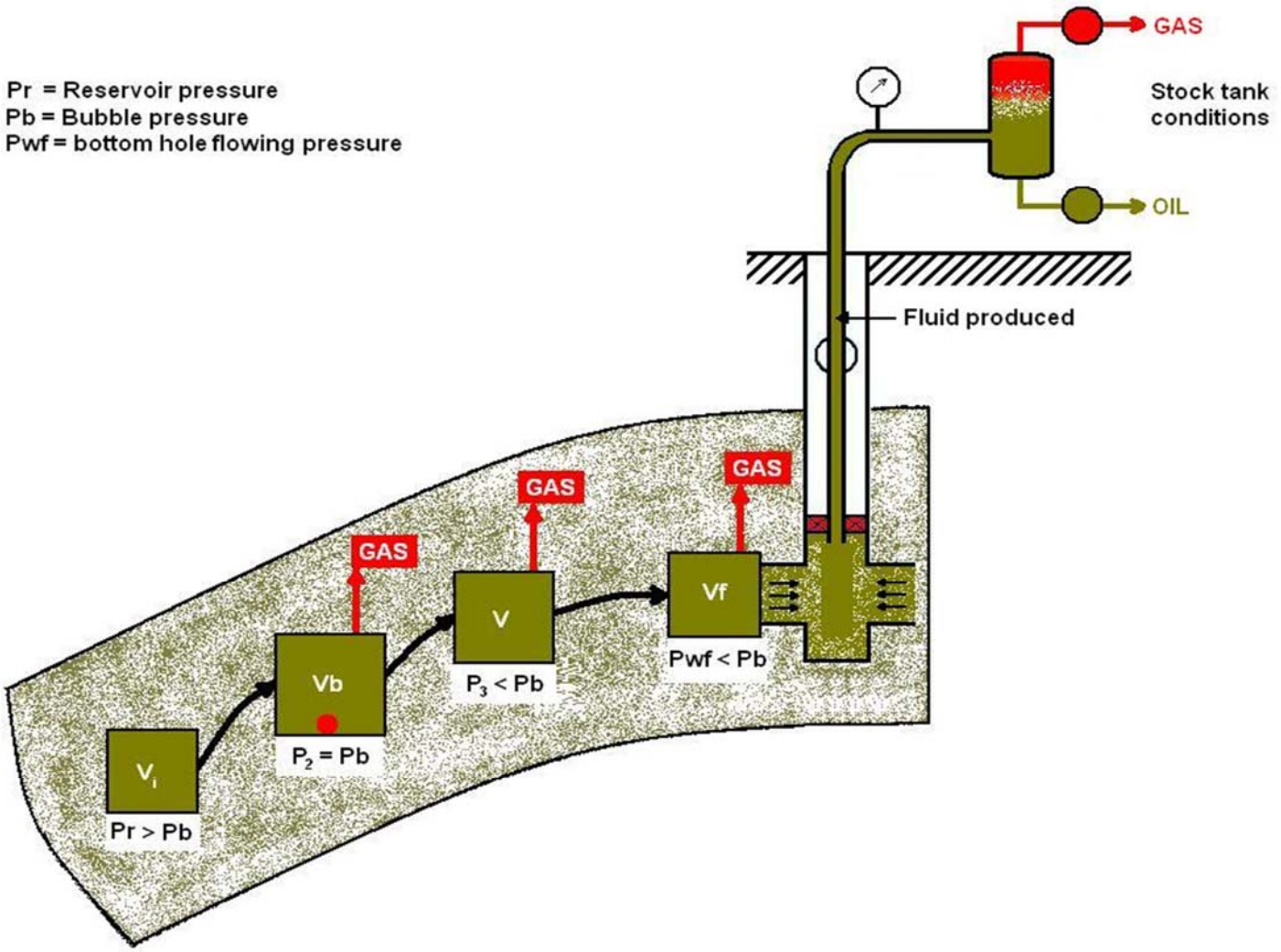




Oil PVT study – Separator test

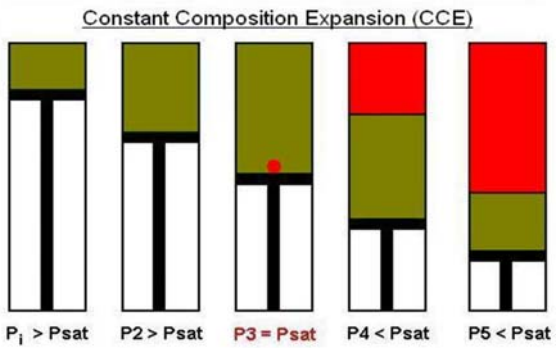
- **Objective**
  - Simulation of field test or process separation scheme
- **Main properties derived from this experiment**
  - GOR
  - Process R_{si}, Process B_{oi}
  - Gas composition at each step
  - Stock tank liquid composition and properties

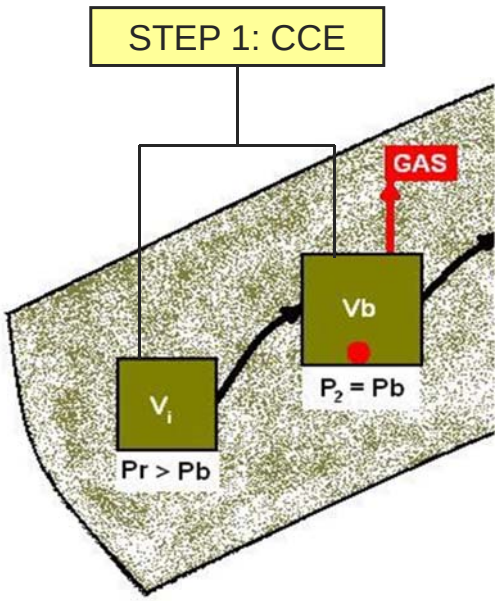


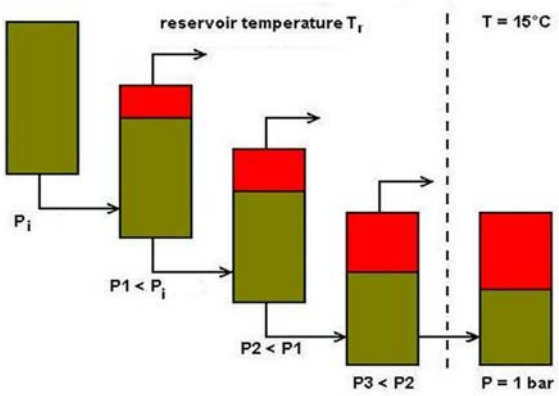


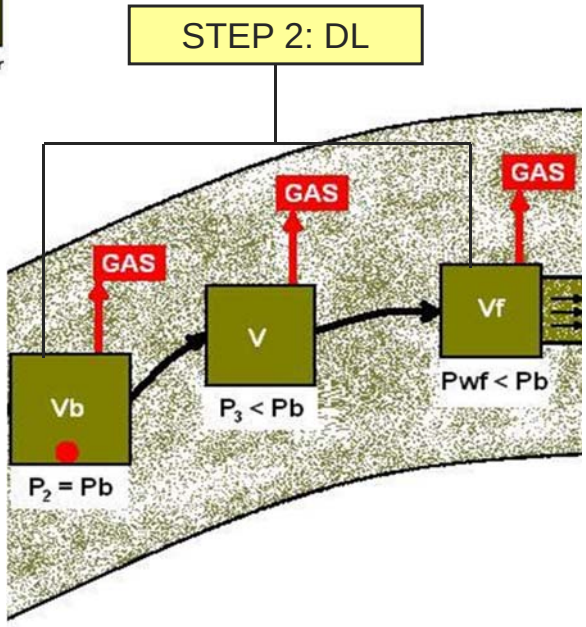
Composite PVT

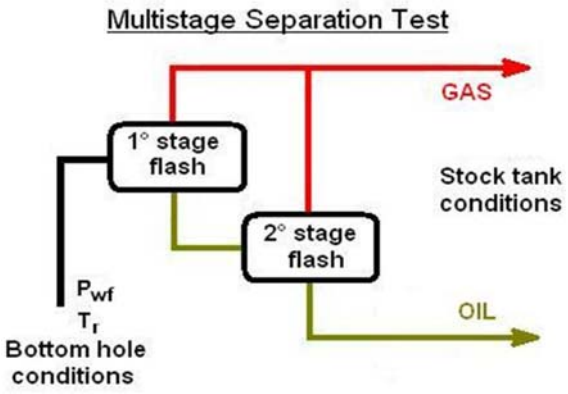
- **Differential liberation corresponds to the conditions in the reservoir:**
  - isotherm
  - progressive depletion
  - liberated gas removed
- **From the well to the stock tank, liberation conditions are different:**
  - temperature varies (from reservoir to stock tank)
  - separation through 1, 2 or 3 stages separator chain
  - gas and oil in contact in the well, specific process through the separation chain
- **Two additional curves are needed:**
  - volume contraction (Boc)
  - gas liberated (Rsc)
- **To describe the well + separators chain to tank process: this constitutes the composite PVT**


Constant Composition Expansion (CCE)
P_i > Psat
P2 > Psat
P3 = Psat
P4 < Psat
P5 < Psat

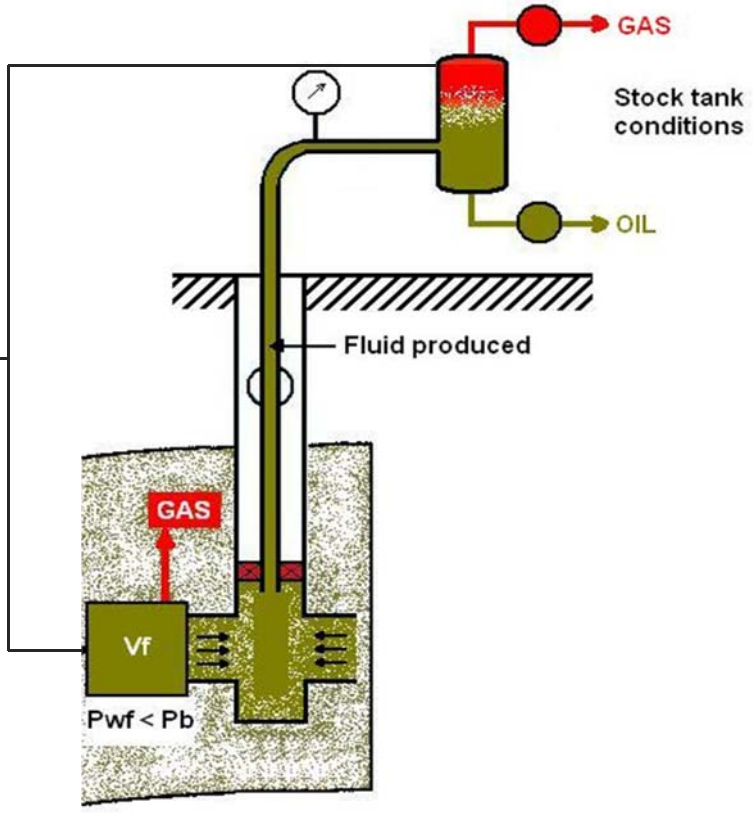

STEP 1: CCE
GAS
Vb
P_2 = Pb
V_i
Pr > Pb


reservoir temperature T_r
T = 15°C
P_i
P1 < P_i
P2 < P1
P3 < P2
P = 1 bar


STEP 2: DL
GAS
GAS
GAS
Vb
V
Vf
P_2 = Pb
P_3 < Pb
Pwf < Pb



STEP 3: MULTISTAGE SEPARATOR TEST



Bo and Rs composites, P > Psat

- **Composite formation volume factor, Bo**

$$Bo^{composite}(P) = Bo^{flash}(Psat) \cdot \frac{Vo(P)^{CCE}}{Vsat(P)^{CCE}}$$

- **Composite dissolved gas, Rs**

$$Rs^{composite}(P) = Rs^{flash}(Psat)$$

Bo and Rs composites, P < Psat

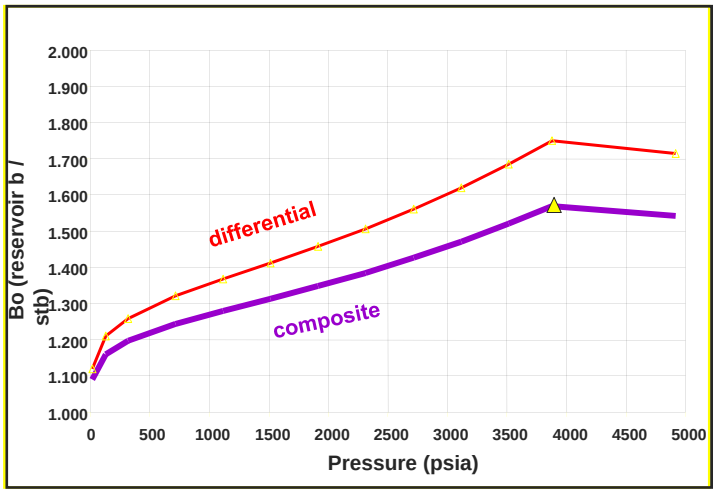
- **Composite formation volume factor, Bo**

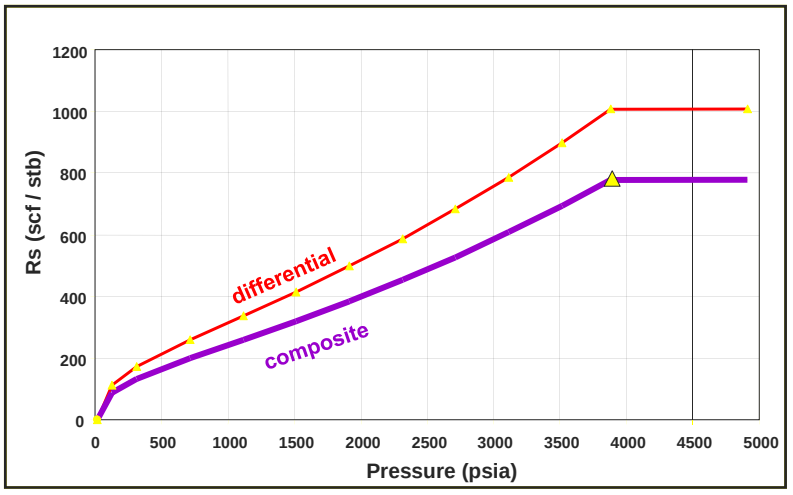
$$Bo^{composite}(P) = Bo^{DL}(P) \cdot \frac{Bo^{flash}(Psat)}{Bo^{DL}(Psat)}$$

- **Composite dissolved gas, Rs**

$$Rs^{composite}(P) = Rs^{flash}(Psat) - \left(Rs^{DL}(Pi) - Rs^{DL}(P)\right) \cdot \frac{Bo^{flash}(Psat)}{Bo^{DL}(Psat)}$$

Composite PVT

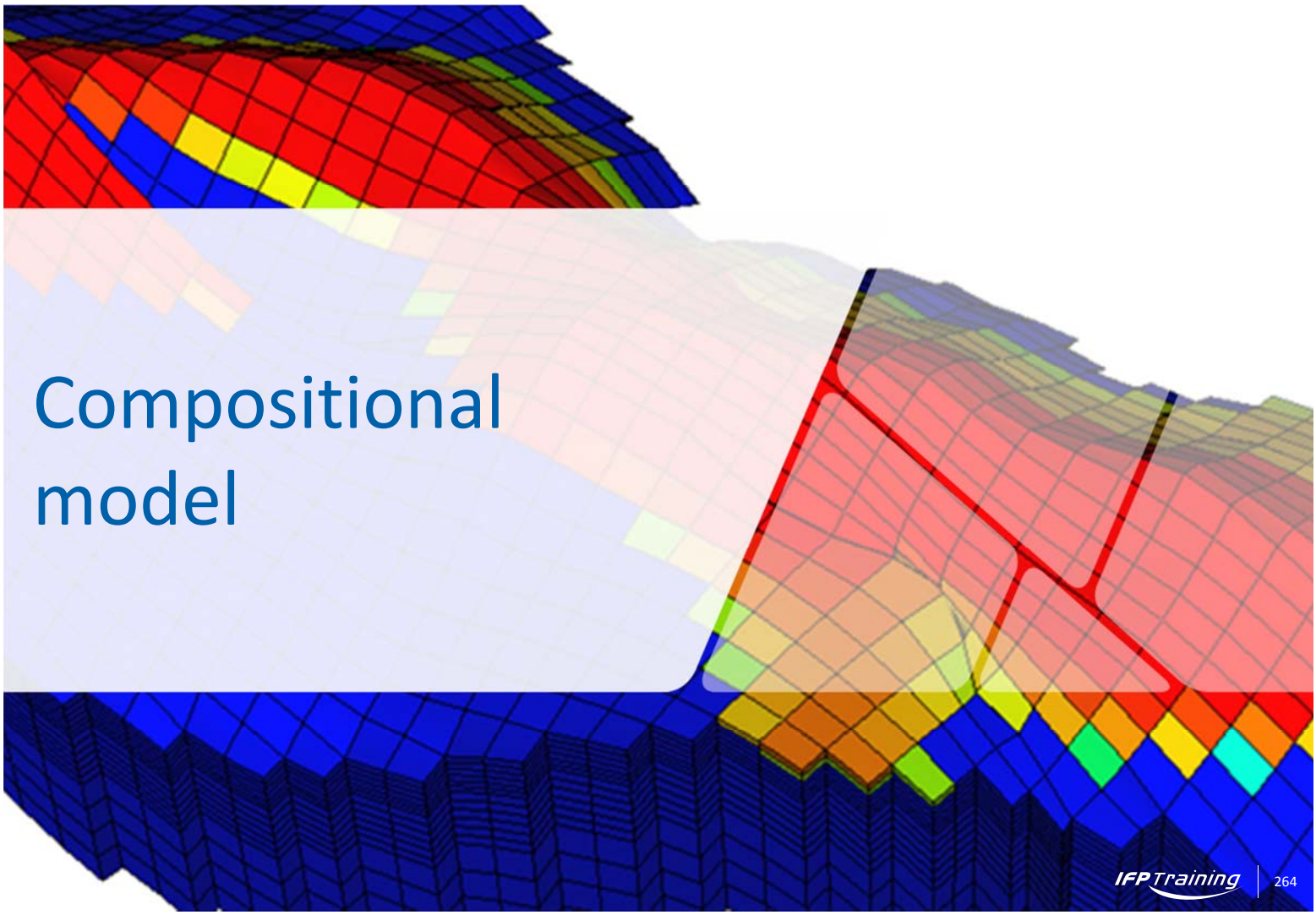




...Which PVT to choose?

- **A fluid sample will follow a composite path between its original location in reservoir and its final destination at surface**

- **First step**
  - Fluid is moving in the reservoir above saturation pressure
  - Volume change versus pressure is identical to CCE
- **Second step**
  - Fluid is moving in the reservoir below saturation pressure
  - Liquid composition versus pressure is identical to a CVD
- **Third step**
  - Fluid has reached the well bore
  - Volume and composition surfaces are identical to a flash process



Compositional model

Compositional model

- **n pseudo-components**
  - C1, C2CO2, C3C6, ….
- **Characteristics of each pseudo-component (concentration, Tc, Pc, Vc, …)**
- **Volumes computed with an Equation of State**
- **Phase equilibrium from**
  - Equation Of State
  - Tables
- **Each pseudo component is present in reservoir gas and in reservoir oil**

Main EOS in reservoir simulators

- **Redlich-Kwong**

$$P = \frac{RT}{V-b} - \frac{aT^{-1/2}}{V\cdot(V+b)}$$

- **Soave-Redlich-Kwong**

$$P = \frac{RT}{V-b} - \frac{a(T)}{V\cdot(V+b)}$$

- **Peng-Robinson**

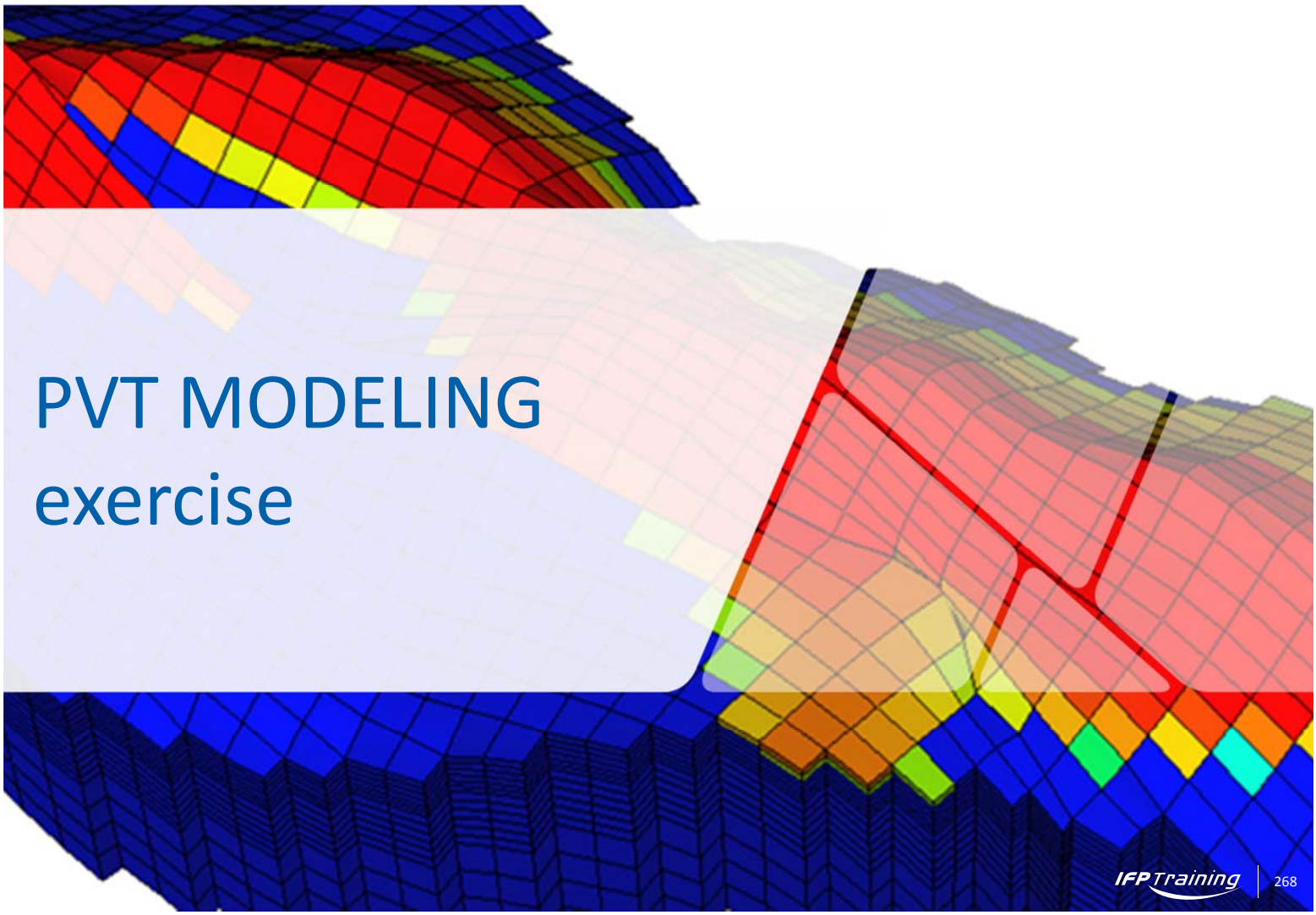
$$P = \frac{RT}{V-b} - \frac{a(T)}{V\cdot(V+b)+b\cdot(V-b)}$$

- **Zudkevith-Joffe**

$$P = \frac{RT}{V-b} - \frac{a(T)\cdot T^{-1/2}}{V\cdot\left[V+b(T)\right]}$$

Key points to keep in mind

- **The PVT model is chosen according to the hydrocarbon type and the production mechanism**
- **The two main PVT models are:**
  - BLACK-OIL: 3 components OIL, GAS, WATER (simplified PVT with tabulated data)
  - COMPOSITIONAL: Equation of State (EOS)
- **PVT properties in BO model:**
  - Formation volume factor Bo= f(P) and solution gas/oil ratio Rs = f(P)
- **PVT experiments in order to determine main fluid properties**
  - Differential liberation: differential FVF and Rs, liberation GOR
  - Constant composition expansion: bubble pressure, compressibility
  - Separator test: composition, viscosity, density, FVF and GOR
- **Composite PVT is used to describe the process from reservoir to surface, the three PVT experiments are combined: DL, CCE and separator test**



PVT MODELING exercise

We define the different PVT analyses (CCE, DL, etc...) and observations (liquid density, GOR, etc...) in the main data tree.

The data-set and project files are designated as ***.PVI**

The export files to the ECLIPSE simulator are designated as ***.PVO**

The print files with the simulation results are designated as ***.PVP**

The main fluid is always called ZI. We may choose the name of the other fluids of the system, such as those corresponding to mud filtrate, swelling fluid, produced by mixtures, after mud decontamination, etc...

ECLIPSE PVTi PVT analyses

Many PVT analyses can be modelled:

- **Single-point experiments:**
  - Flash
  - Multiphase flash
  - Bubblepoint
  - Dewpoint
  - Saturation pressure
  - Saturation temperature
  - Critical point
- **Pressure depletion**
  - CCE
  - CVD
  - DL
- Injection study
  - **Swell (by mole fraction)**
  - **Swell (by GOR)**
  - **Vaporization**
  - **First contact miscibility**
  - **Multiple-contact miscibility**
  - **Multi-contact test**
- Separators
- Composition with depth

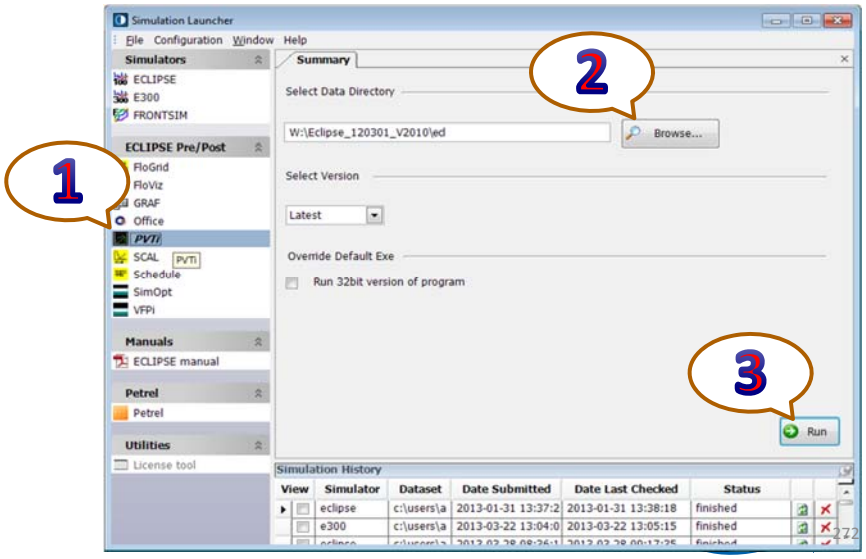
Any of these can be used, either to enter laboratory measurements and perform a regression to better characterize the fluid model, or as a prediction for a given fluid model.

Typical PVT modeling workflow

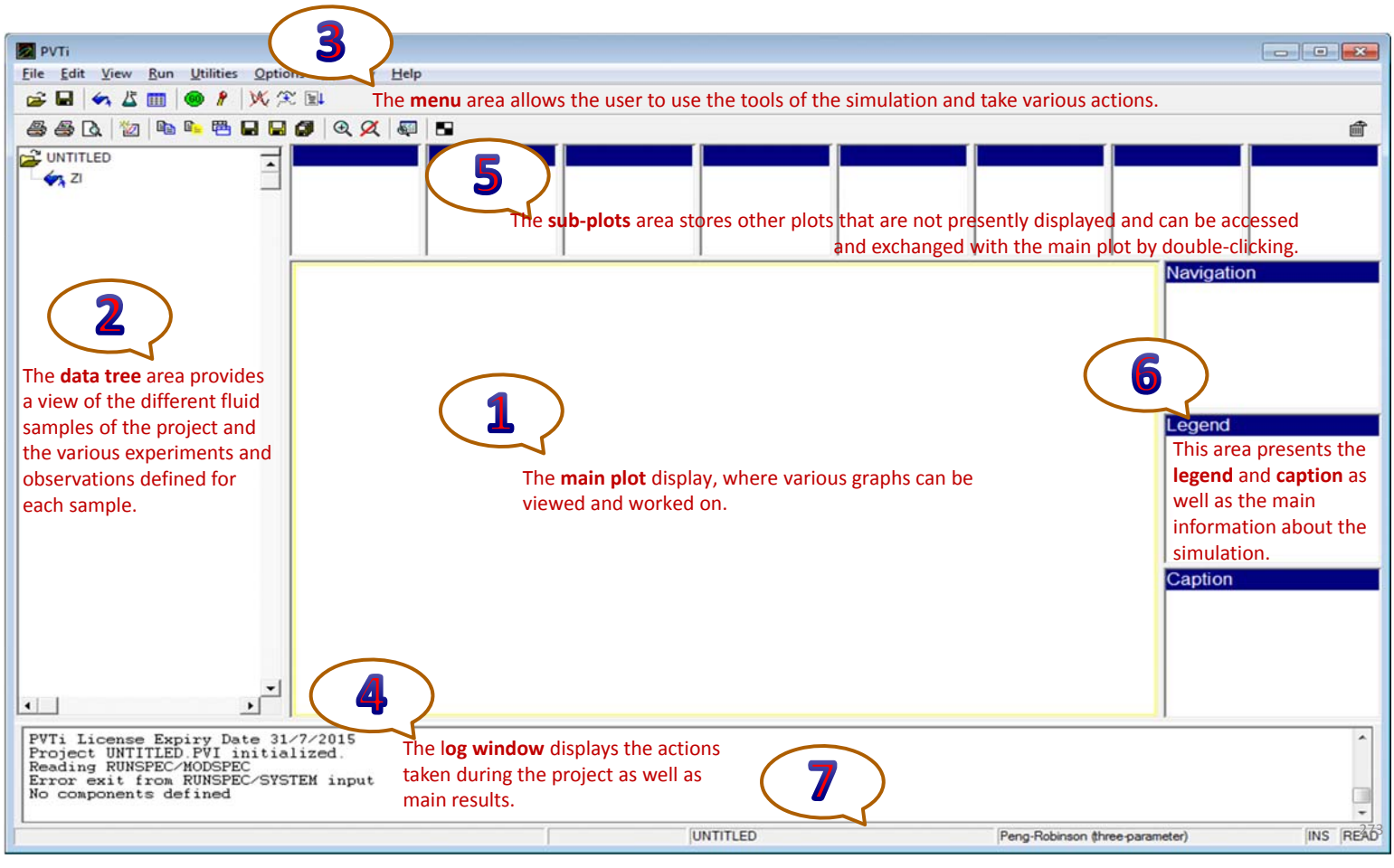
1. **Analyse PVT report.**
2. **Enter fluid composition.**
3. **Enter carefully selected PVT analyses from a PVT report.**
4. **Plot basic fluid characteristics (fingerprint plot, phase envelop, etc...).**
5. **Enter all existing PVT measurement results for the corresponding fluid.**
6. **Run a simulation and plot observed vs. calculated results.**
7. **Run regression for the improvement of the fluid model.**
8. **Split the heavy pseudo-components**
9. **Run regression for the improvement of the fluid model.**
10. **Group components when necessary.**
11. **Run regression.**
12. **Export fluid properties.**

PVTi: Getting started

- Start the ECLIPSE program Launcher.
- Click on the PVTi button.
- Select the version and working directory as required.
- Start the software by clicking Run.

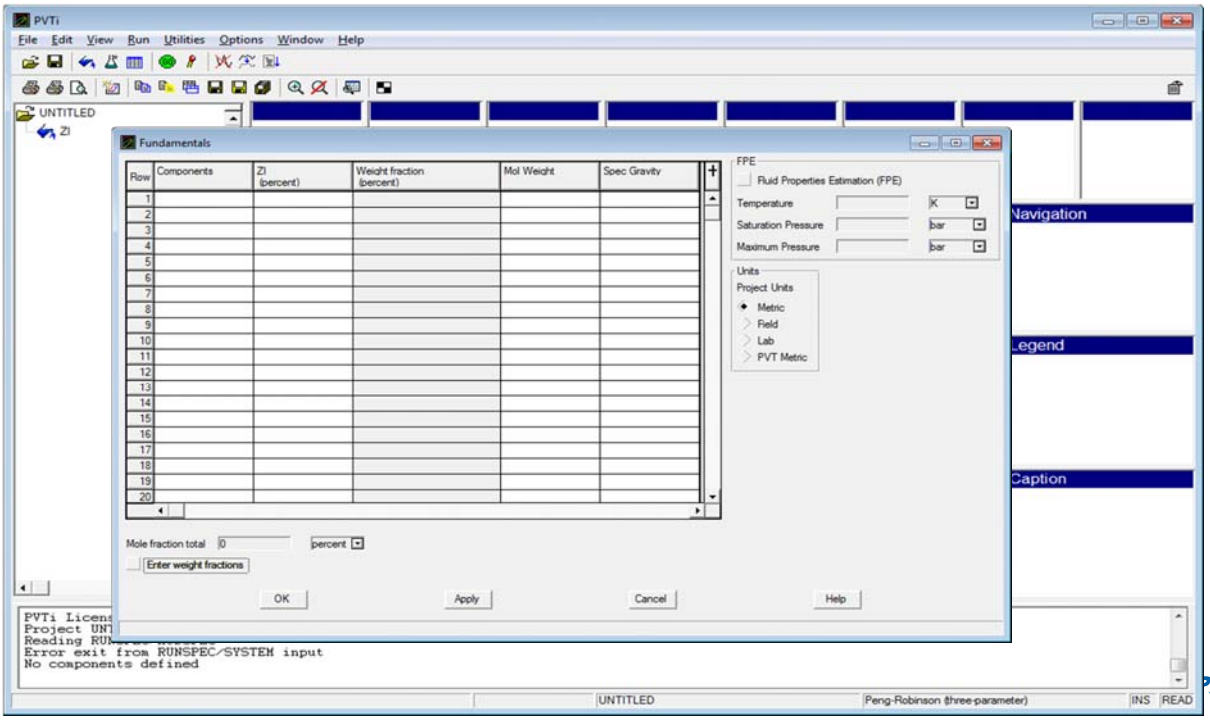


The main window is compartmentalized in various areas:



Opening a new file in PVTi

- **For this exercise, we will work with the report: ALWYN WELL 3/9a-N3, in order to build a fluid model for ECLIPSE Black oil simulation.**
  - When ECLIPSE PVTi is opened, a window prompts the user to select the data-set file. Select "Annuler". You should get the window as shown in the figure when a new file has opened.



ECLIPSE PVTi basic features and worfkflow for Alwyn 3/9a-N3 PVT report

- **Two sets of separator oil and gas samples were analysed in the laboratory. One set was recombined using a corrected GOR to perform a complete PVT study (reservoir fluid), including:**
  - P-V relation by CCE
  - single-stage separator
  - two-stage separator
  - DL
  - viscosity by CCE

- **The reservoir fluid, recombined using a corrected GOR of 145.2 Sm^3/m^3, has a saturation pressure of 257.5 bar(g), whereas the reservoir pressure is 445.0 bar(g). There is no bottomhole sample for this well.**

Summary of ECLIPSE PVTi analyses and observations:
Alwyn 3/9a-N3 PVT report

The analyses and observations to be entered in ECLIPSE PVTi for this well, and the source and content of the tables in the PVT report are described. They will be entered as presented. Please go through the different analyses and refer to the PVT report to build your fluid model.

- **P-V relation by CCE (CCE1)** — **TABLE VIII**
  - Relative volume
  - Liquid density
- **Single-stage separator (SEPS1)**
  - Liquid molar fraction
  - Vapour molar fraction — **TABLE X**
  - GOR
  - Stock-tank oil density — **TABLE IX**

Summary of ECLIPSE PVTi analyses and observations:
Alwyn 3/9a-N3 PVT report

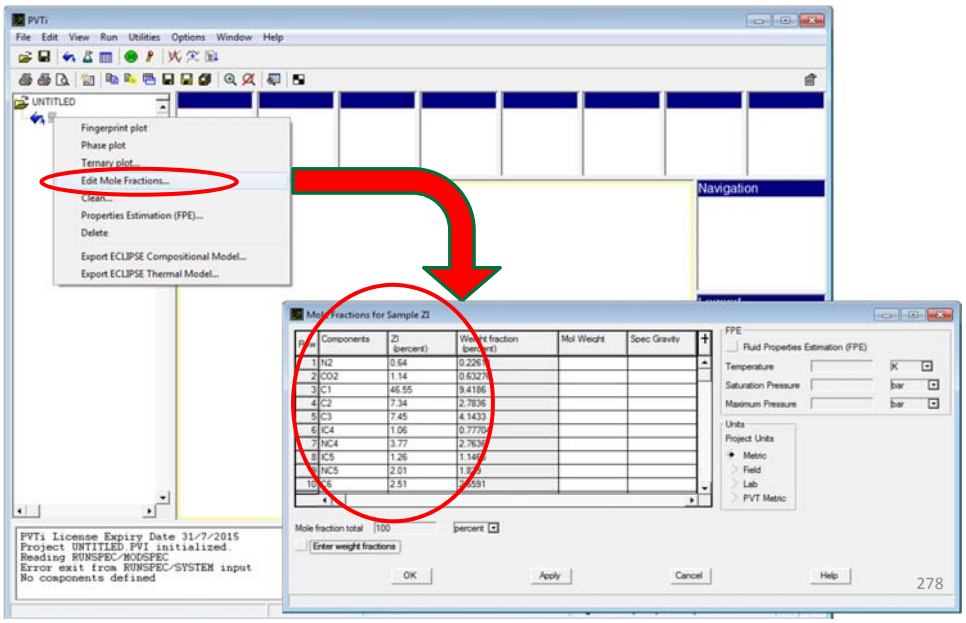
- **Two-stage separator (SEPS2)**
  - Liquid molar fraction
  - Vapour molar fraction — **TABLE XII**
  - GOR
  - Stock-tank oil density — **TABLE XI**
- **DL (DL1)**
  - Oil relative volume
  - Liquid density
  - Z-factor
  - GOR — **TABLE XIII**
  - Vapour molar fraction → **TABLES XIV, XV**
- **Viscosity by CCE (CCE2)**
  - Liquid viscosity — **TABLE XVI**
- **Saturation pressure (PSAT1)**
  - Saturation pressure — **TABLE I**

Enter a new fluid

To enter the fluid composition, *use the Table X from the PVT report in order to create ZI*. In the case, the "Fundamentals" window is not open, to enter the fluid composition: right-click on "ZI" go to *Edit Mole Fractions*... enter the composition of the calculated reservoir fluid.

You can observe on Table X, that you have a pseudo-component C11+, enter the mole weight and the specific gravity for the C11+. Click on *Apply* and check that the total is 100%.

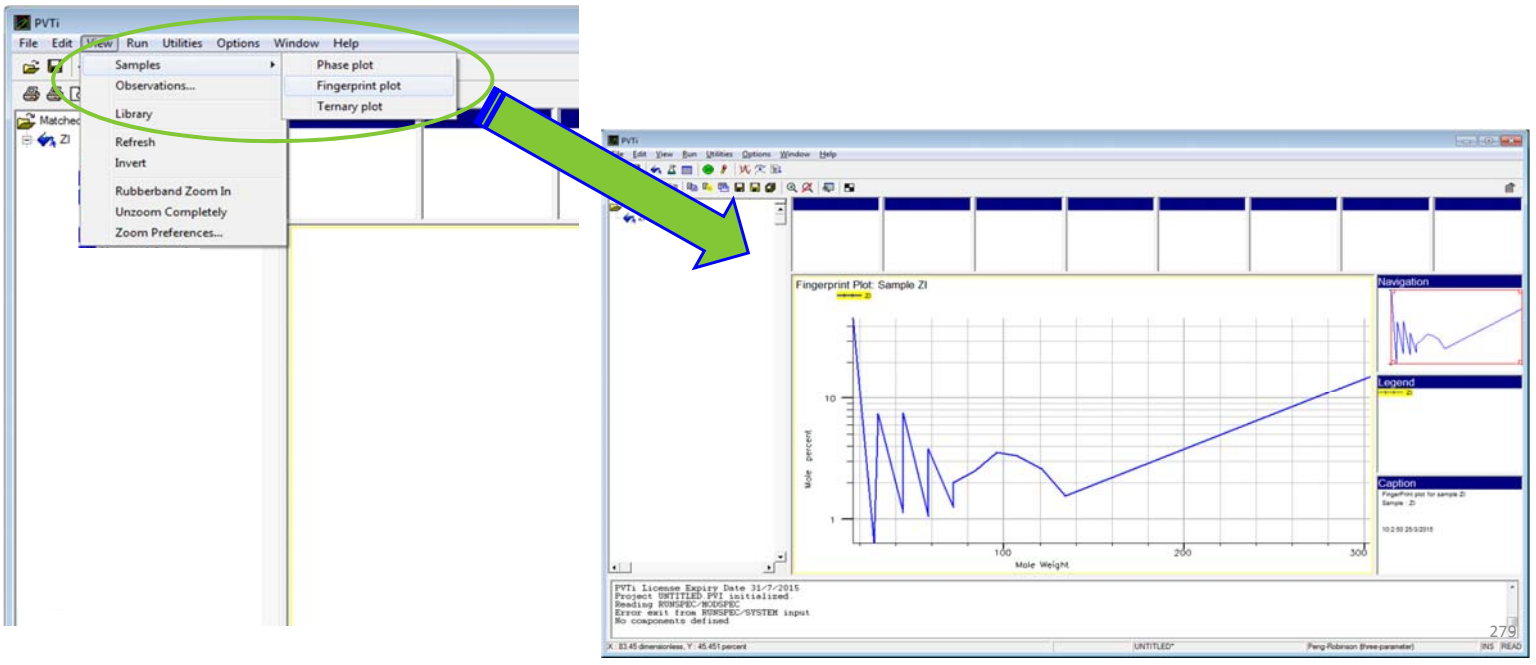
Close the window!



Plot the main fluid characteristic plots...

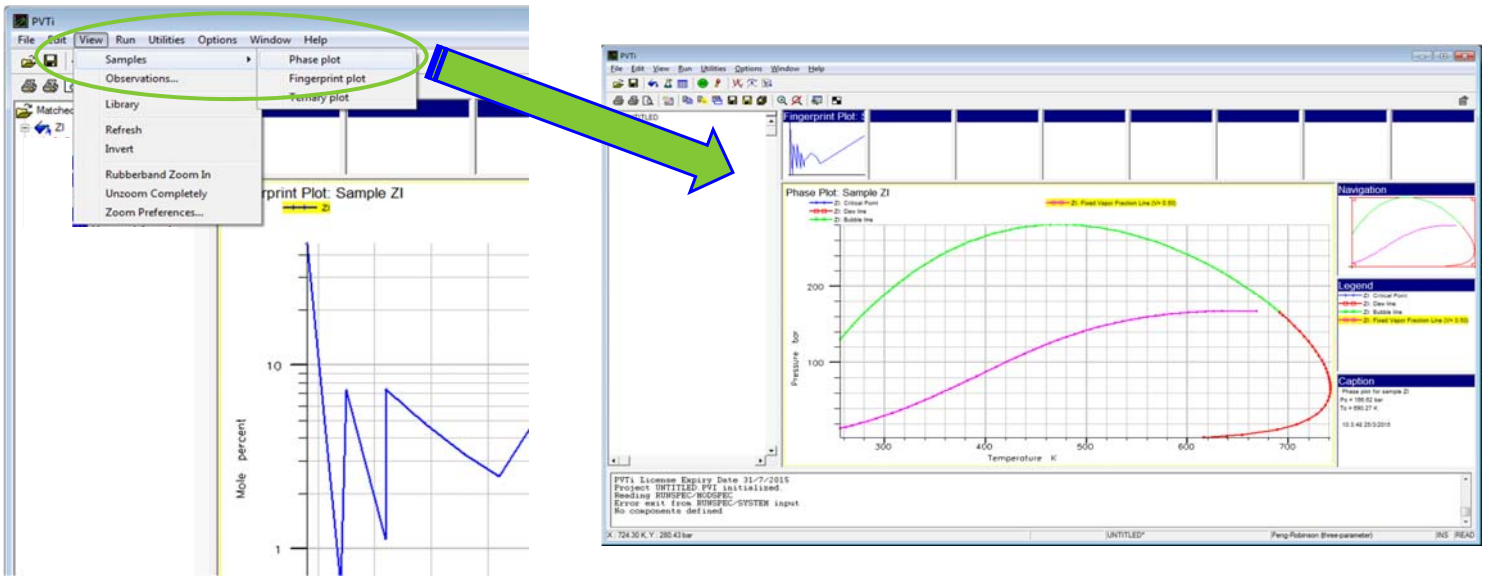
The reservoir fluid, called by default ZI, appears now in the data tree. Look at the main characteristics of the fluids.

a. ***Go to View / Sample / Fingerprint plot* in the menu. You should observe the plot as in the figure, showing the composition *vs.* the mole weight of each component. Another alternative is to right click on ZI and select *Fingerprint plot* directly.**



Plot the main fluid characteristic plots...

b. Do the same to observe the phase plot (*View / Sample / Phase plot*, or alternatively right click on ZI, or grab and drag ZI to the main graphic window). The plot should appear as shown in the figure.



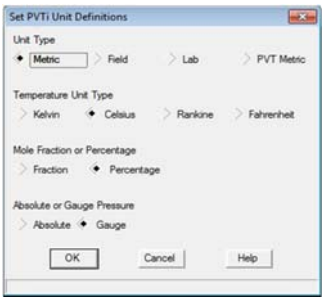
Note: Each time a new window opens, the previous one from the main plot area goes to the sub-plots area. You may navigate between these by selecting one and double-clicking.

Main windows for fluid characterization...

Navigating through the main windows, you can see the main information and options and where they can be changed. *Feel free to navigate through them!*

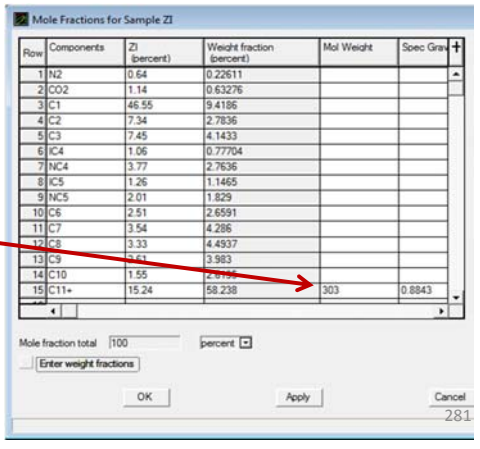
Units: To view and select the units, click on *Utilities / Units*.

The units system we use for this exercise is Metric. *Check the units!*



Mole fractions: To observe the fluid composition, go to *Edit / Sample / Composition*. The compositions of all the samples are displayed in this window. This is where you entered the fluid composition. To view compositions fluid by fluid, right-click on one of the fluids and select *Edit Mole Fractions*.

You can check that the mole weight for the C11+ pseudo-component is 303 and the specific gravity is 0.8843!



Main windows for fluid characterization...

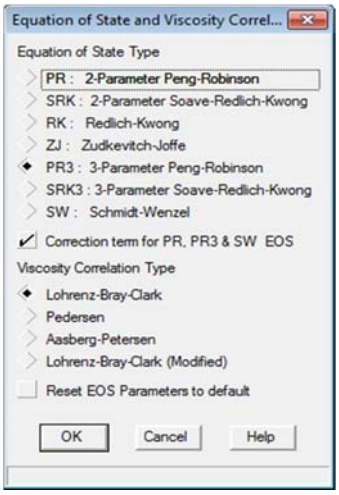
EOS: Go to *Edit / Fluid Model / Equation of State*.

You can select from four different EOSs and four different viscosity equations.

The default selection is PR3 (Three-Parameters Peng-Robinson EOS)

with correction term and Lohrentz-Bray-Clark for the viscosity correlation.

These are the best adapted in our case, don't change them!



Components: Go to *Edit / Fluid model / Components* and go through the different tabs. *Names* displays all the components and their types, whether they are defined by library, characterized or user defined. The type can be modified from this tab. In *Complete* the full characteristics of the each component are displayed (mole weight, Pc and Tc, Ω_a and Ω_b, etc...). This tab is for viewing purpose only. In *Library* are displayed the library characteristics of any component type defined as "Library" in the *Names* Tab. In the *User* tab, user defined characteristics can be entered. As there are no user-defined component types for this fluid model, it is empty. In the *Characterization* tab, the pseudo-components (here C11+) are defined as per chosen critical properties and acentric properties correlations.

Check the different options but leave them as the default ones (Kesler-Lee) when you leave the window...

Adding experiments...

a. Go to *Edit / Experiment*.... A window opens where you can add a new experiment or edit the existing ones. Click on *Add*...

b. Let's begin with a CCE Experiment: Once you have clicked on *Add*... then *Pressure Depletion / Constant Composition Expansion*...

c. On the PVT report, you find The Constant Composition Experiment for the reservoir fluid "ZI" (Table VIII)

d. In the *General Tab* you choose the fluid sample, *Next*... specify the fluid and temperature then *Back*...

e. In the *Observation Tab* add the pressure data required for the experiment and select the column heading for the observations. Choose "Pressure", "Relative volume" and " Liquid density", then click on *Next*... fill in the table and click on *Next*...

f. The window goes back to the *General Tab*.

g. Add the experiment **One stage separator (SEPS1)**: *Edit / Experiments... / Add / Separators*... then fill in the items:

   General Tab: ZI.

   Observation Tab: Define Temperature, Pressure, Liquid density, GOR (Table IX).

   Components Tab: Toggle '*Liquid mole frac.*' and '*Vapour mole frac.*' (Table X).

   Then *Next*...

   Observation Tab: Fill in Temperature, Pressure, Liquid density, GOR (Table IX).

   Liquid mol. frac. and *Vapor mol. frac. Tabs*: Fill in tables with data in Table X.

Adding experiments...

h. Add the experiment **Two stages separator (SEPS2)**: ***Edit / Experiments... / Add / Separators***... then fill in the items: Follow the same procedure but defining two stages...

Observation Tab: Temperature, Pressure, Liquid density, GOR (Table XI).

Component Tab: Liquid mole fraction and Vapour mole fraction for the two stages (Table XII).

i. Add the experiment **Differential liberation (DL1)**: ***Edit / Experiments... / Add / Pressure Depletion / Differential Liberation***... then fill in the items (procedure is similar to CCE & SEP:

General Tab: ZI, specify fluid type, temperature.

Observation Tab: Pressure, Liquid density, Oil relative volume, GOR, Vapour Z-factor (Table XIII).

Component Tab: Vapour mole fraction (Tables XIV and XV).

j. Add the viscosity data using the experiment **Constant Composition expansion (CCE2)**: ***Edit / Experiments... / Add / Pressure Depletion / Constant Composition Expansion***... then fill in the items:

General Tab: ZI, specify fluid type, temperature (Table XVI).

Observation Tab: Pressure, Liquid viscosity (Table XVI).

k. Add the experiment **Saturation Pressure (PSAT1)**: ***Edit / Experiments... / Add / Single Point / Saturation Pressure***... then fill in the items:

General Tab: ZI, temperature (Table I).

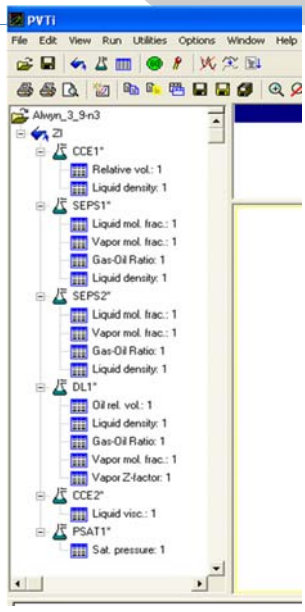
Observation Tab: Saturation pressure (Table I).

ZI is the global composition of reservoir fluid in Table X

Adding experiments...

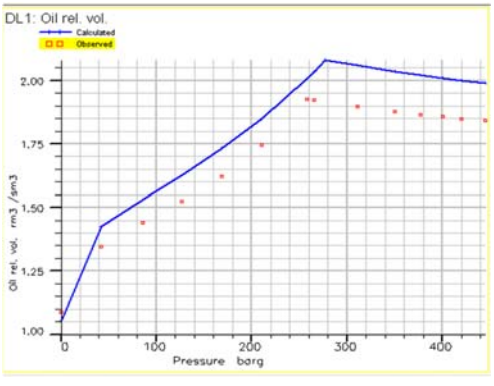
Once you have added all the experiments,

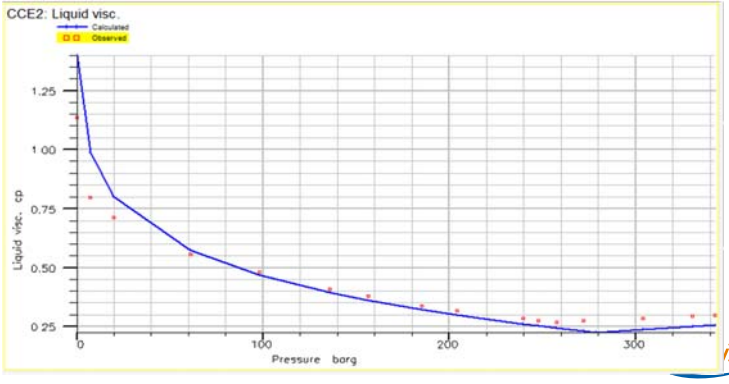
your data tree should look like the Figure:



Save your file!!!!

To plot the results of the experiments, right click on the experiment you want to plot and select Plot.





Main windows for fluid characterization...

Experiments: Go to *Edit / Experiment....* A window opens where you can either add a new experiment or edit the existing ones. Another alternative to *Edit Experiments* is to right click on the experiment in the data tree and to select *Edit*.... For example, if you edit un experiment you can observe the temperature and various pressures for which the observations were entered...

Observations: To edit the observations, go to *Edit / Observations*.... *You can practice this point after performing the "Adding experiments" instructions!* You open a window, which will appear as shown in the figure. On the left the *Experiment Type* is defined.

The ones that have already been defined for the current fluid model and that appear in the data tree are marked by an asterisk (*).

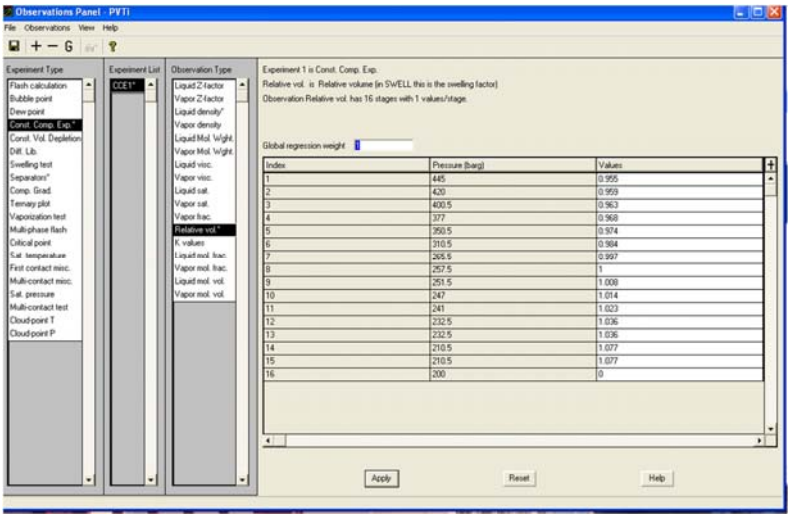
When selecting one of them, the next *Experiment list* will define the experiments for each category. For example, if you have several experiments on the data tree: When selecting one, the list of corresponding observations appears.

The ones marked with * are already selected and entered.

More can be added or some can be removed by using the + and – buttons of the menu of the *Observations* panel.

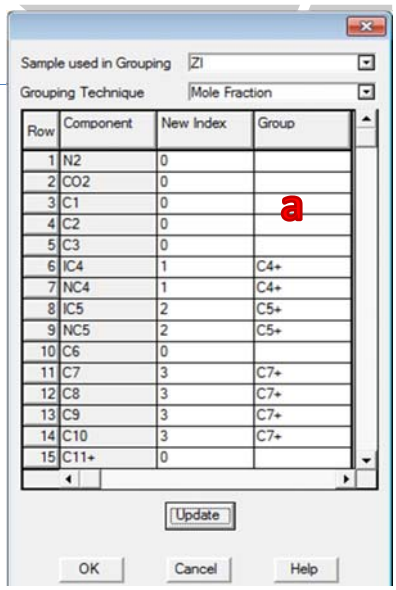
By selecting them, you can see the experimental data that have already been entered. You can add an observation for viewing even if there is no corresponding experimental data available.

Close the window when you finish looking at the observations!



Running a simulation

Go to *Run / Simulate* or alternatively, click on the green *Go* button . You can compare the observed and calculated observations for each experiment defined in the data tree. For example, compare the observed and calculated saturation pressures at the end.

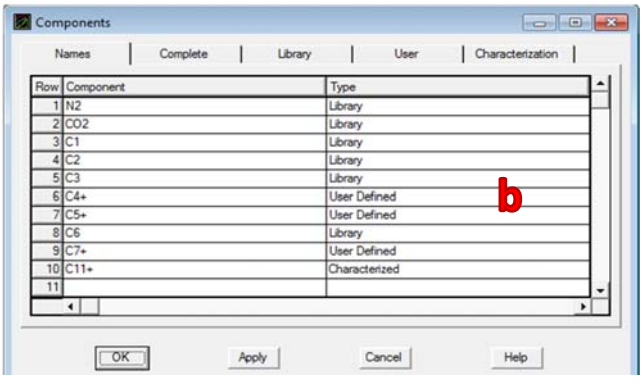


Grouping pure components

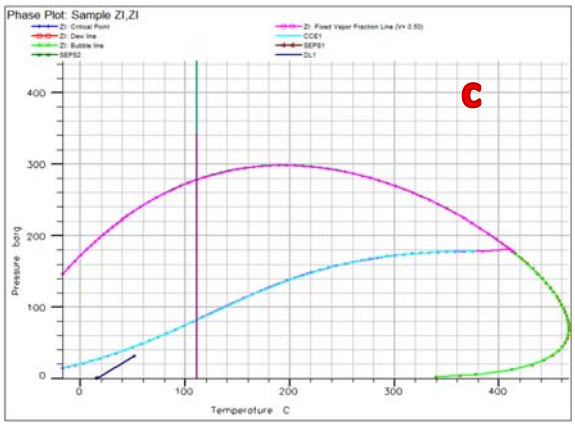
Grouping will help to match the laboratory data and obtain a better fluid model. While grouping, we need to ensure that the phase envelope is not going to be much affected.

a. Go to *Edit / Fluid Model / Group*.... We will group by mole fraction as selected by default. For the components we will group together, we will enter an index in the "New Index" column. Enter 1 for IC4 and NC4, 2 for IC5 and NC5, and 3 for C7, C8, C9, and C10. Select Update. A default group name appears in the Group column. Select OK to exit the window.

b. Check on the fluid composition. You now have 10 different components. When checking in the components window (*Edit / Fluid Model / Components*), you can see that the components you have just defined are now of the type *User defined*, with their characteristics in the *User* tab.



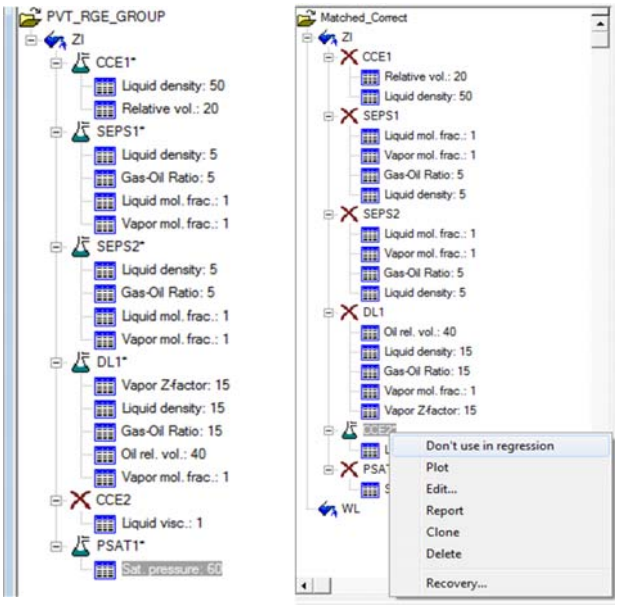
Grouping pure components



c. We will now compare the phase envelope to the one before grouping. Select *Superimpose* and plot the new phase plot in the same graph as the previous one. You can see that the two phase plots match very well. You can also superimpose the two fingerprint plots to review your grouping.

d. Save this project as Grouped.PVI (in the menu *File / Save as*...). We will use the fluid model with the grouped pseudo-component for the regression.

Performing a regression

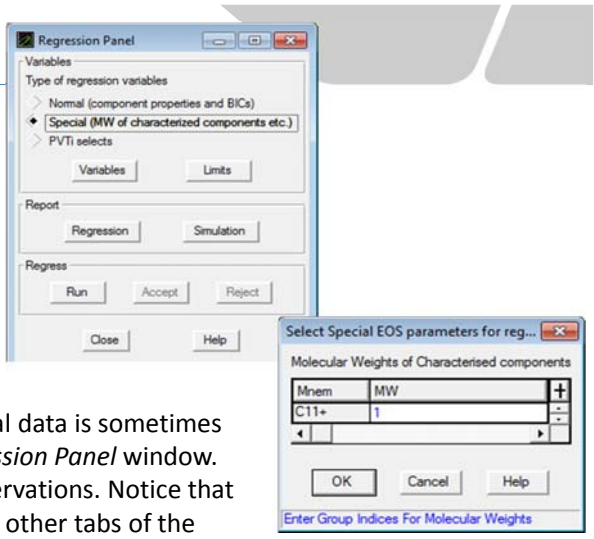


a. Use the data-set you have just saved after grouping **Grouped.PVI** .

b. We will first set the weight of the regression for all the observations:

- Saturation pressure is a very important criterion for an EOS match! So set the weight of Psat as 60 (right-click on Sat. pressure).
- Viscosity is always the last to be fitted in a regression... So set its weight to zero, right-click on CCE2 and select *Don't use in regression*.
- Set the weights of the other observations as follows: CCE1 relative vol. to 20, Liquid density to 50; SEPS1 Gas-Oil Ratio to 5, Liquid density to 5; SEPS2 Gas-Oil Ratio to 5, liquid density to 5; DL1 Oil rel. Vol. to 40, Liquid density to 15, Gas-Oil ratio to 15, and vapor z-factor to 15.

Performing a regression

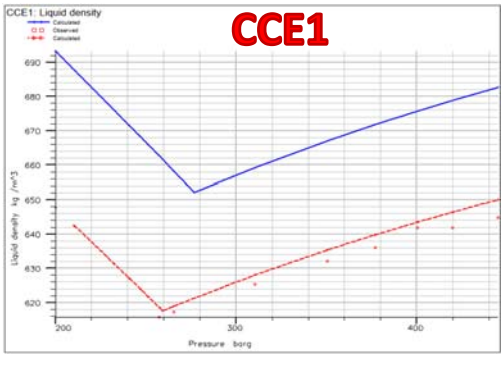


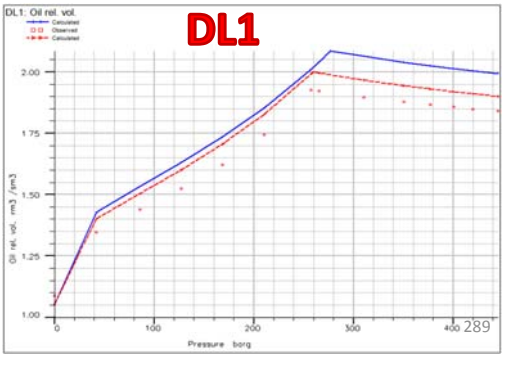
c. Before you proceed with the regression, plot the different experiments and select the ones you would like to monitor (there is no space for all of them). A good selection is to monitor the CCE1 experiments, the SEPS2 Gas-Oil ratio and the DL1 experiments.

d. Go to ***Run / Regression***... Select the *Special regression (MW of characterized components etc...)*. Select variable and enter 1 for the C11+ MW regression, *OK*, *Run!*

e. Observe the curves during the real time regression, the fit of the experimental data is sometimes improved. Check the regression report by clicking on *Regression* in the *Regression Panel* window. Check the new values of the calculated saturation pressure and all other observations. Notice that DL1 oil relative volume is improved but still needs to be worked on. Go to the other tabs of the *Regression Report Panel.* In *Modifiers*, observe the change that was made on the mole weight of C11+ to achieve this fit. It is very important to check the modifiers when doing a regression, to ensure no unrealistic or too important changes were made. *Accept the regression!*

f. Save the project as **Special.PVI** !



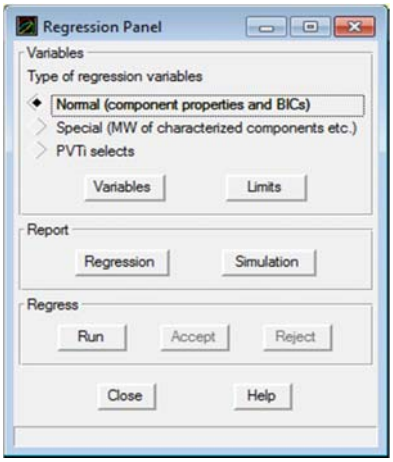


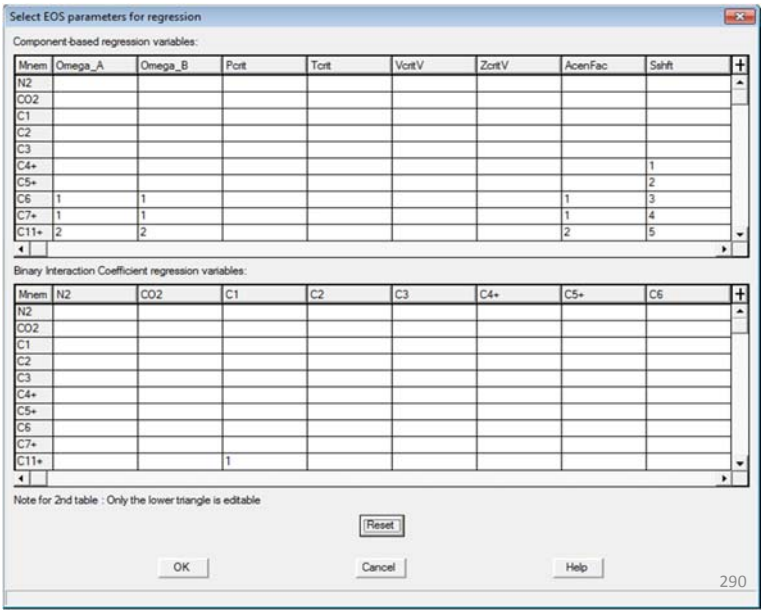
Performing a regression

g. We are now going to improve the regression on file **Special.PVI** using other fitting parameters. In the "Regression Panel" select the *Normal (component properties and BICs)* regression variable type.

h. Critical parameters are well defined for pure components, so we should avoid selecting them. In general, when deciding which variables to choose, consider the following sensitivities: critical pressure and temperature of Ω_a and Ω_b for the saturation pressure; Volume shifts for Z-factor, densities, etc. The rules for the matching parameters selection are as follows*: In the same column, entering a same number for different parameters means they will be varied dependently. A different number means the parameters are matched independently. For the top table of the variable panel, all columns are independent, even if the same number is selected in the same row. For the bottom table (BIC variables), number must be different in a row for the parameters to be matched independently.*

i. We usually focus at first on pseudo-components.
Use the values shown in the Figure...





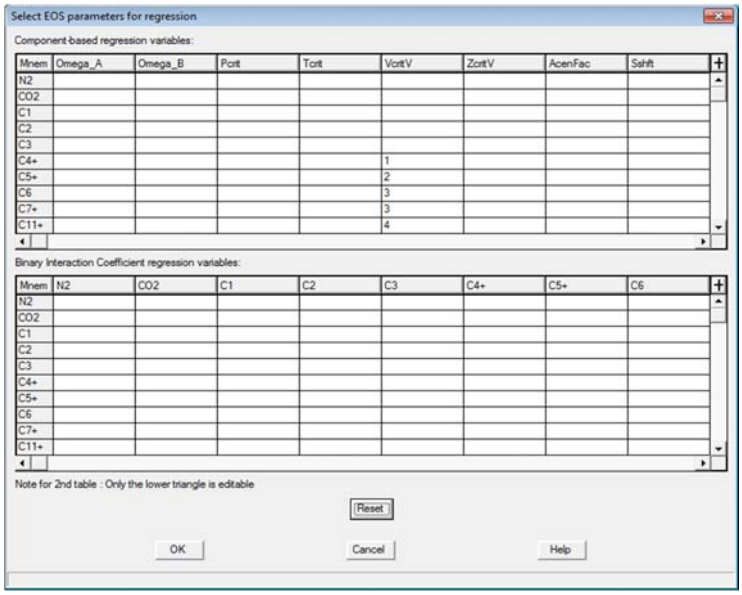
Performing a regression

g. Close the window and click on *Run* to run the regression!

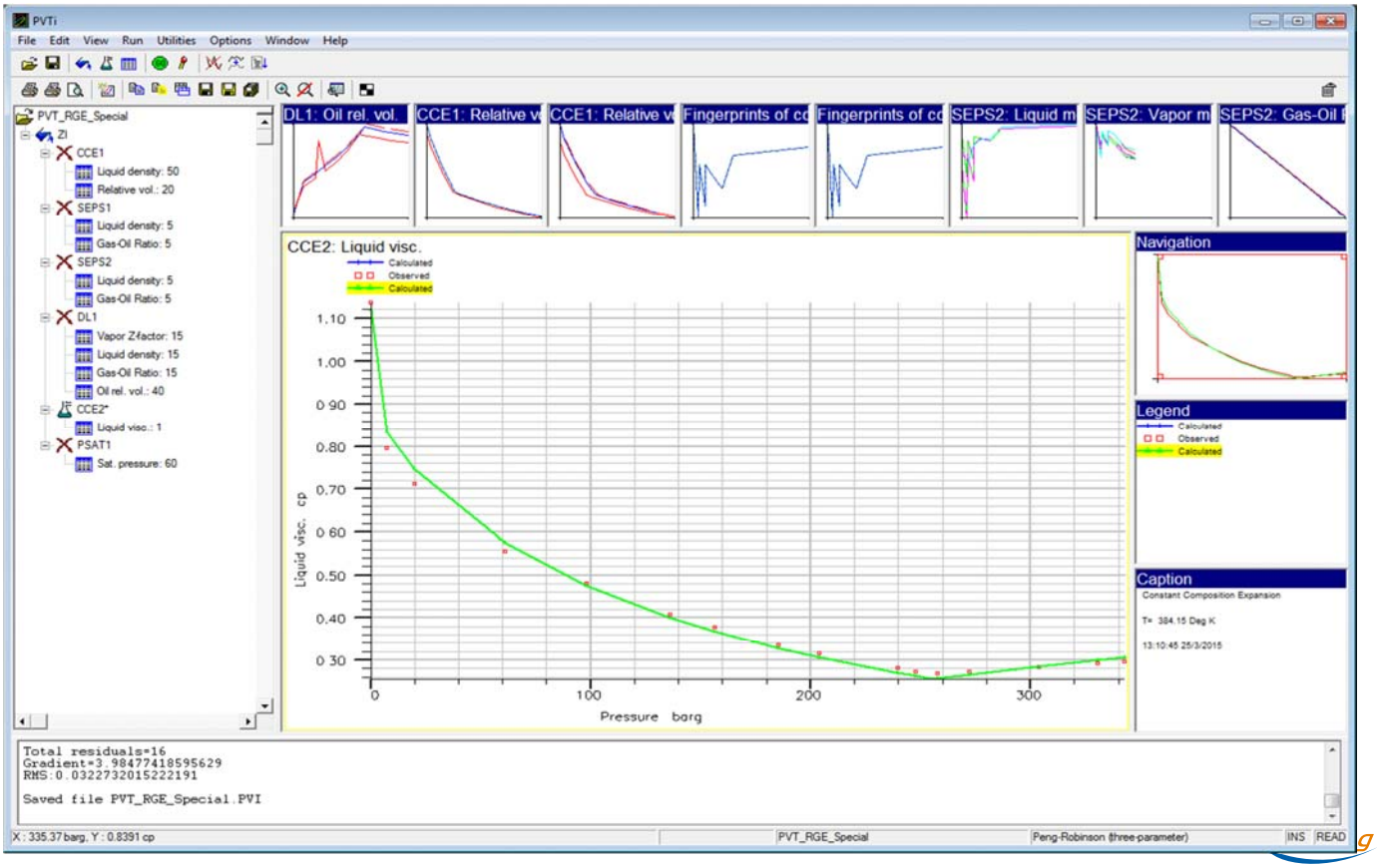
h. Observe the calculated versus observed results on the graphs. Check the regression report (*Regression* button in the *Regression panel*). Most observations are now matched to an acceptable limit. Density is within less than 1%. The saturation pressure is not as matched as it was after the Normal regression, but it is still within an acceptable range. Accept the regression.

g. We now need to match the viscosity data. We first remove all the observations from the regression using the *Don't use in regression* by right-clicking on each experiment (CCE1, SEPS1, SEPS2, DL1 and PSAT1) except that of the viscosity observation. Set the weight of the CCE2 liquid viscosity to 1, making sure that CCE2 is *Used in regression*. Plot the CCE2 liquid viscosity to follow the regression in real time. Go to the *Regression Panel* and select *Variables*. Clear all the selected regression variables by clicking *Reset*. Enter values as in the figure for VcritV (C6 and C7+ have the same number to make them dependent during the regression).

h. Run the simulation. Check the match from the *Regression Report Panel*.



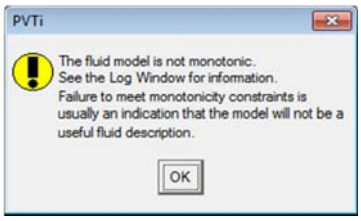
Viscosity match...



Performing a regression

NOTE:

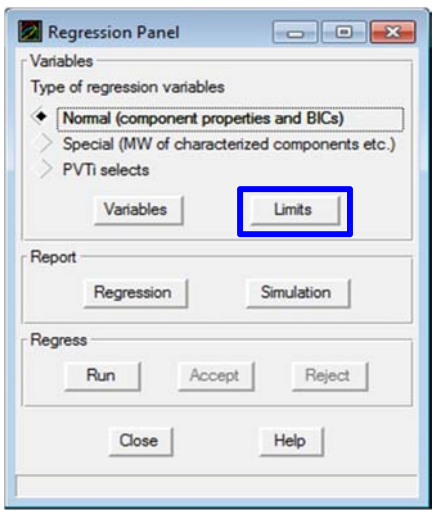
If you get a warning message informing you that the model is non-monotonic. Check the log area for the reason. The message will inform you that the way the variables were varied, C7+ critical volume for viscosity is less than that of C6. Reject the regression.

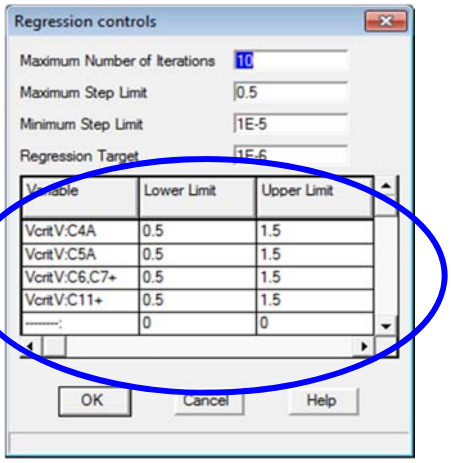


In the Limits panel put all the regression limits to between 0.5 and 1.5. Run the simulation. Check the regression report. This match is even better than the previous one: *plot the experiments!!!*

Accept the regression.

Save your project as '**Matched.PVI**'

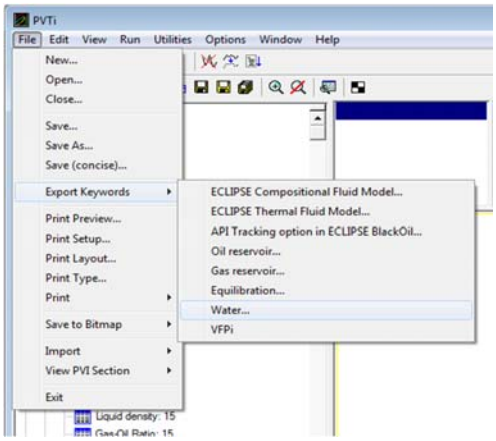


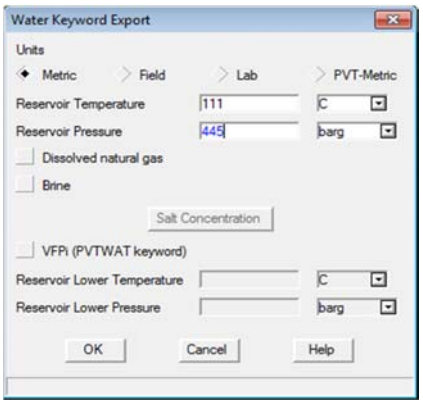


Exporting water correlations

From your **Matched.PVI** file:

a. Go to *File / Export Keywords / Water*.... Enter the reservoir temperature of 111 ° C and the reservoir pressure of 445.0 bar(g). The water salinity is around 17,000 ppm in this area. Because the exact value is not given accurately in the PVT report and because this amount of salt will not change the output much, we will not enter further information.



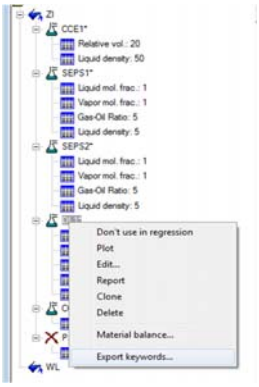


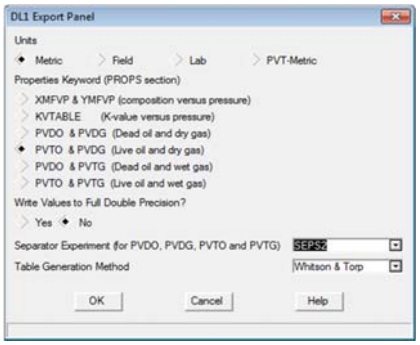
b. Click OK and save the file as **PVTW.PVO** when prompted. The information you have just saved is displayed in the Output display window. PVTW is the keyword that will be used later in the ECLIPSE simulation for the water PVT properties. The different arguments of the PVTW keyword are the reference pressure, Bw, Cw and μw at reference pressure, and the "viscosibility" = (dμw/dP)/μw)

Exporting ECLIPSE BO tables

We will now export the ECLIPSE Blackoil keywords of the fluid model we have just matched, as tables. From your **Matched.PVI** file:

a. Right click on DL1 and select *Export Keywords*... Select PVTO & PVDG (Live oil and dry gas) properties keywords. Select the separator Experiment SEPS2 and click OK. Save the file as **PVTO.PVO** when prompted.





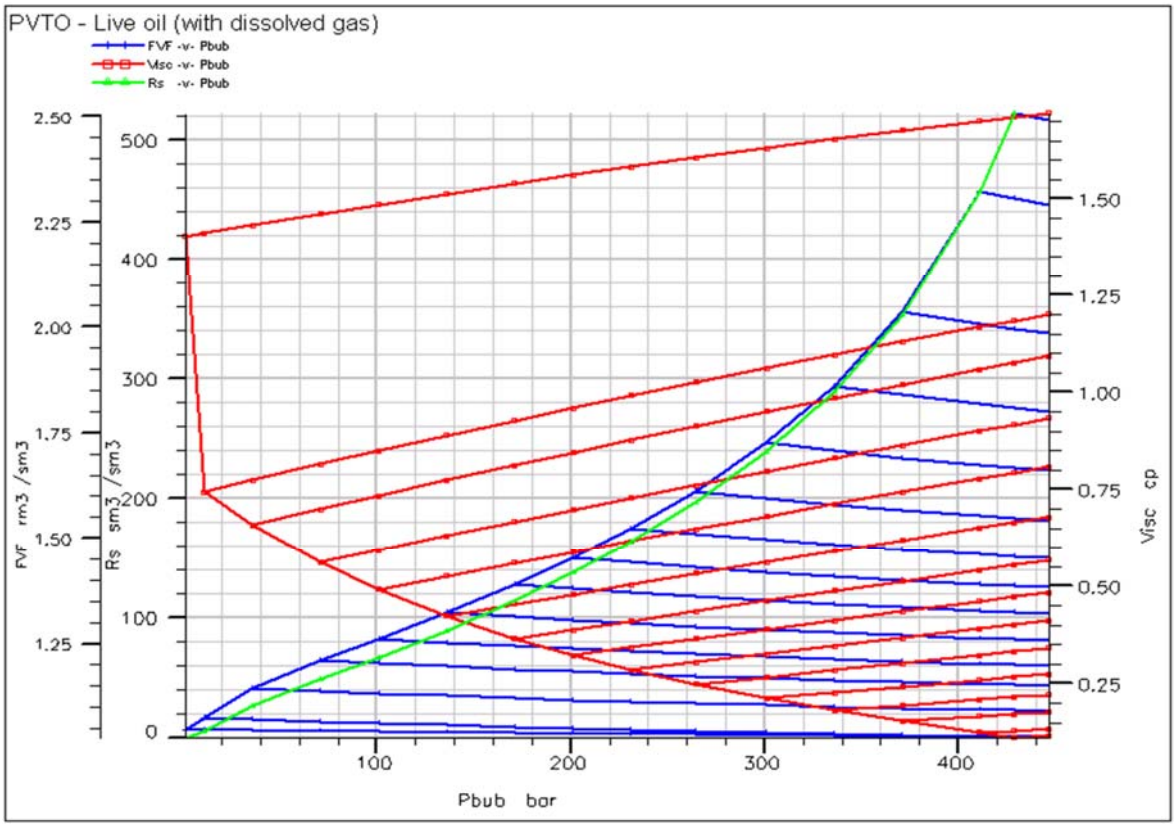
b. The ECLIPSE Blackoil keywords are now created and appear in the Output Display window. Export keywords for ECLIPSE Blackoil are computed using the DL1 pressures.

c. Look in the Output display window. The keywords:

DENSITY provides the densities of O, W and G at surface conditions.

PVTO (live oil with dissolved gas) provides the dissolved gas (Rs), pressure, Bo, and μ. As you can observe, the table consists of different sub-tables, each one for a given Rs corresponding to the Psat defined in the experience DL2.

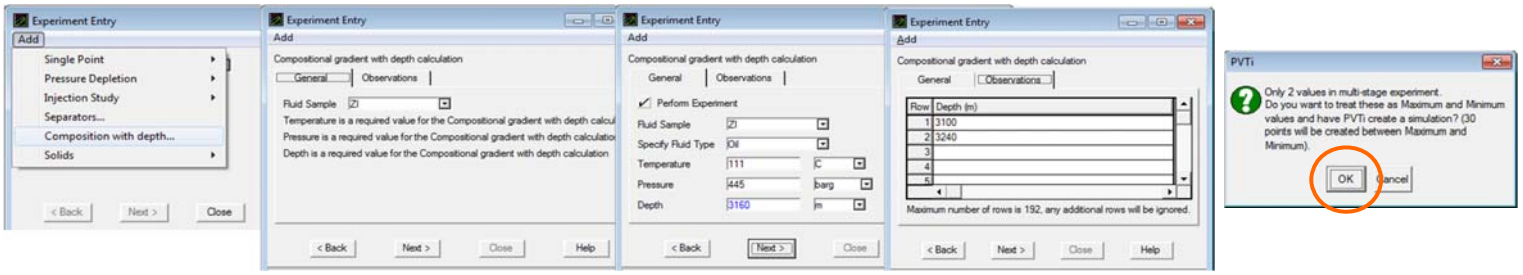
PVDG provides the pressure, Bg and μg (the pressure are the values provided in the DL1 experiments).



Exporting ECLIPSE BO equilibration keywords

We now need to export the keyword for the definition of Rs versus depth. To generate the equilibration keyword, we need to define an experiment of composition versus depth.

a. Go to ***Edit / Experiments*** and Add *Composition with depth....* The fluid ZI is already selected. Click *Next*. Change the fluid type to Oil. Enter the reservoir temperature 111 ° C. Enter the reservoir pressure as 445 bar(g) and the depth as 3160 m. In the observation tab, enter the depth 3100 m in the first row and 3240 m in the second. The intermediate depth is automatically generated and filled by ECLIPSE PVTi. Click *Next*. Say OK to the message, the experiment COMPG1 is now included in the data tree!



b. Right-click on this new experiment and select Export Keyword.... Select PBVD/PDVD equilibration keyword. Save the file as **PBVD.PVO** when prompted.

c. Look in the Output display window. The keywords:

PBVD (Bubble point versus depth) provides the depth entered in the COMPG1 experiment and the bubble point pressure.

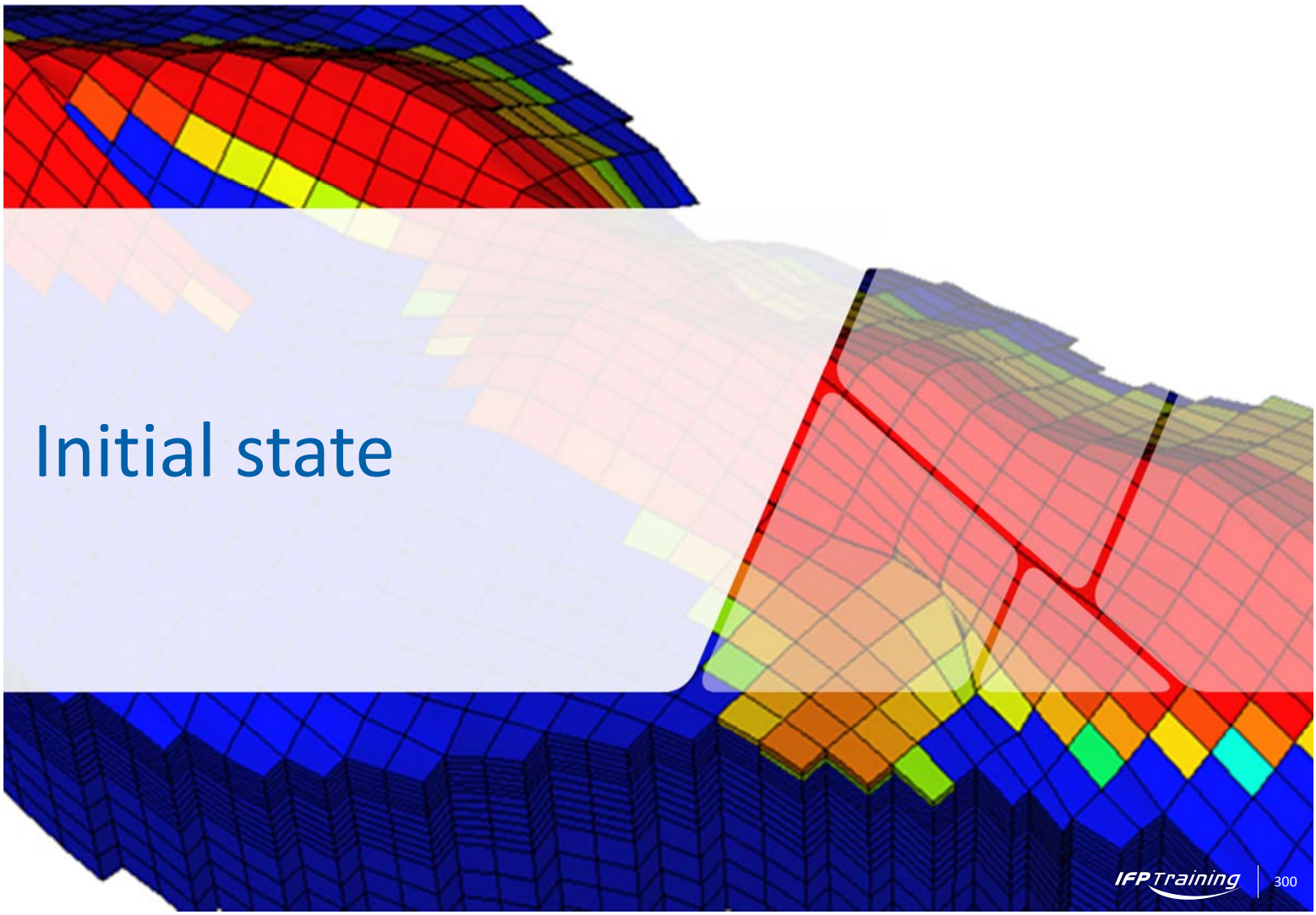


Dynamic reservoir simulation
Data review: Initialization

IFP Training

Data review: initialization

- Initial state 300
- Contacts 310

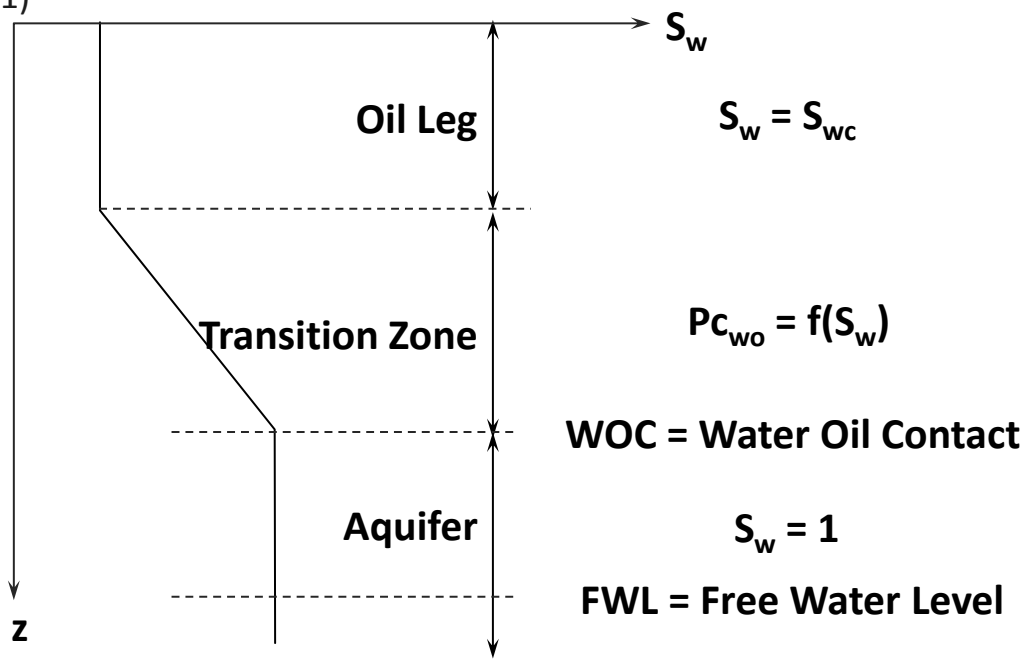


Initial state: summary

- **The reservoir is in static equilibrium**
- **The objective is to set up:**
  - Initial pressures
  - Initial saturations
- **The initial state is correct when original volumes in place are correctly calculated**
- **Main data influencing Original volumes in place are:**
  - Net Pore volume
  - Saturation Height Functions (influenced by Pc curves and fluid densities)

Initial state: water-oil contact definition

- **Three main intervals can be defined:**
  - HC leg (Sw = Swc = Irreducible water saturation)
  - Transition zone (Swc < Sw < 1)
  - Water leg (Sw = 1)



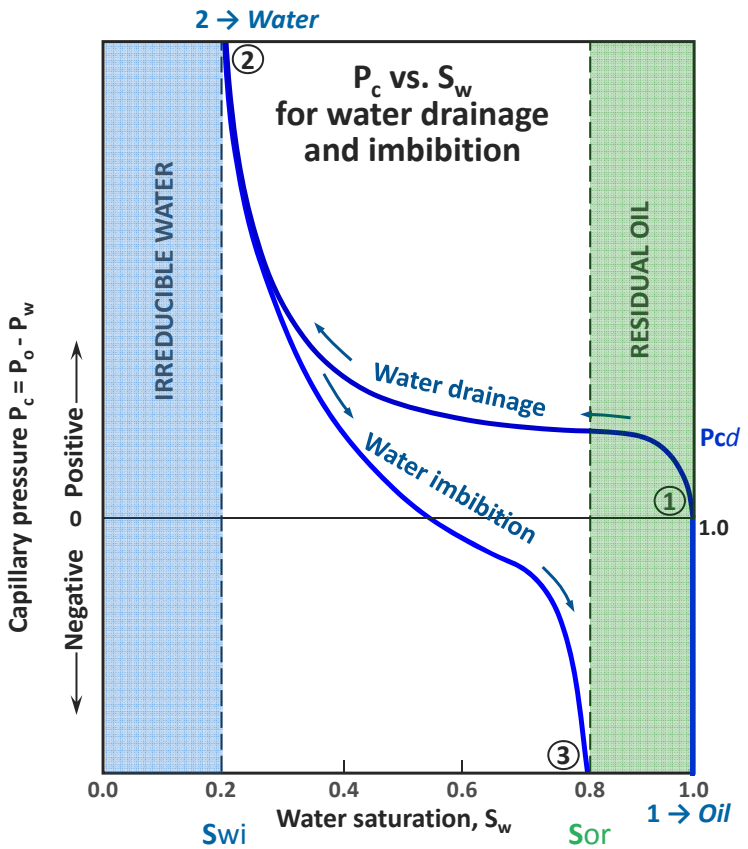
Capillary pressure curves

The model initial equilibrium saturation distribution is established with drainage capillary pressure curves.

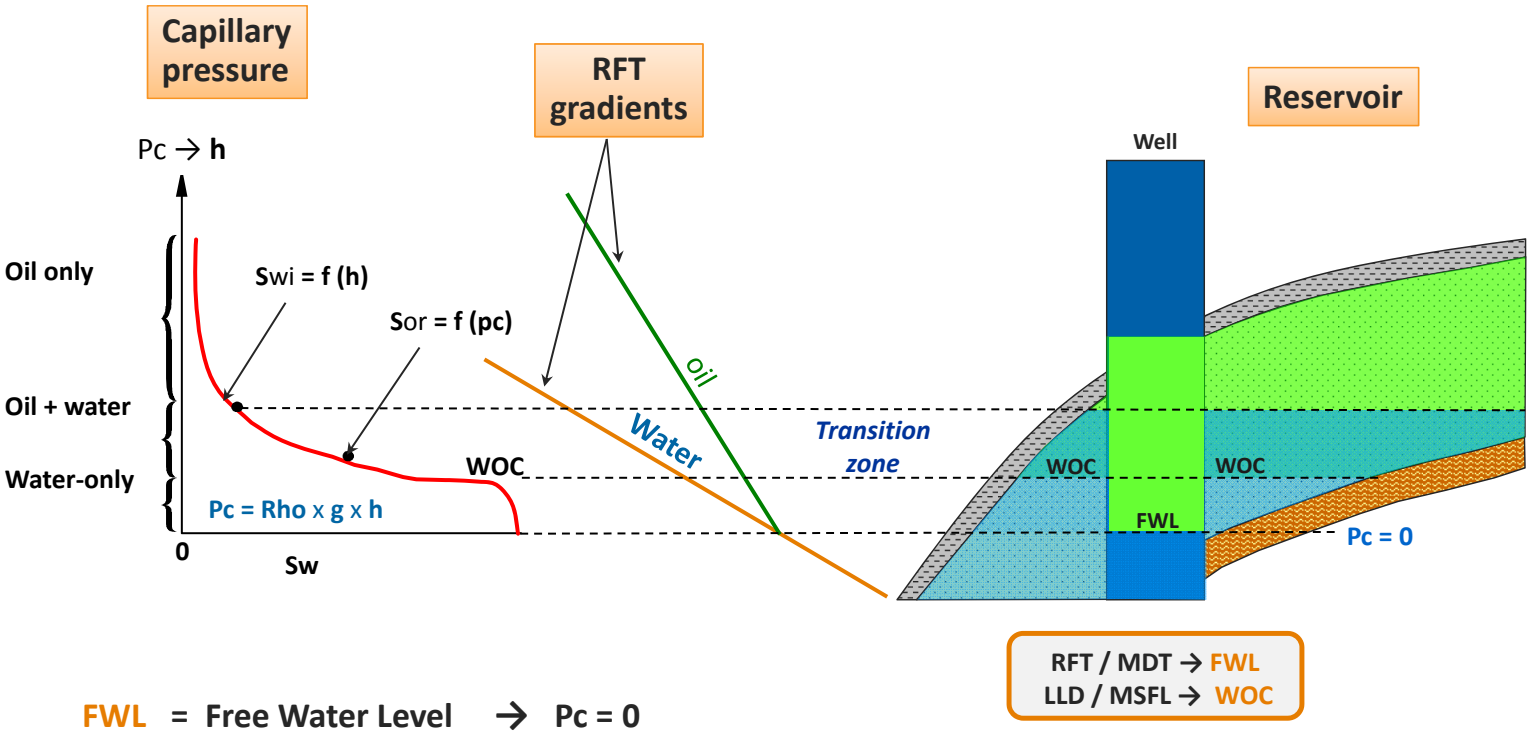
Swi: irreducible water saturation
(≠ inital water saturation)

Sor: residual oil saturation

Pcd: Displacement cap. Pressure



Capillary pressure in the reservoir

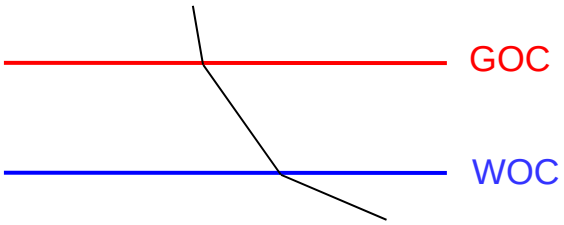


FWL = Free Water Level → Pc = 0

WOC = Water-Oil Contact → Displacement pressure (Pc*d*)

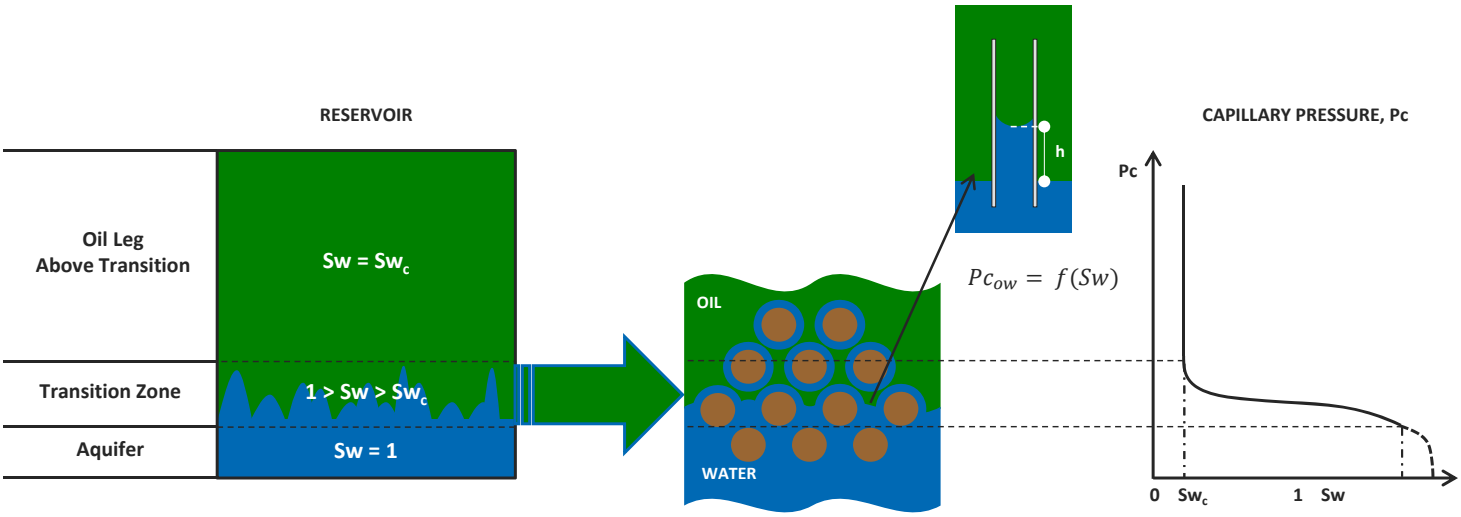
Initial state: pressure calculations

- **Pressures gradients are proportional to fluid densities**



- **Pressures changes at interface can be derived form Pc curves**
  - At the gas oil interface: Po (GOC) = Pg (GOC) - Pcgo (GOC)
  - At the water oil interface: Po (WOC) = Pw (WOC) + Pcwo (WOC)
- **In order to calculate the initial pressure, it is sufficient**
  - To give the pressure at a reference depth
  - The location of the contacts and the capillary pressures at the contacts

Initial saturation distribution



$$Po = Po_{ref} + \rho_o g Z$$

$$Pw = Pw_{ref} + \rho_w g Z$$

$$Pc_{ow} = Po - Pw$$

Sw in the transition zone
OOIP calculation

Initial pressure distribution

Hypothesis:

- **Reservoir at initial equilibrium (most often gravity):**

$$Po = Po_{ref} + \rho_o g Z$$

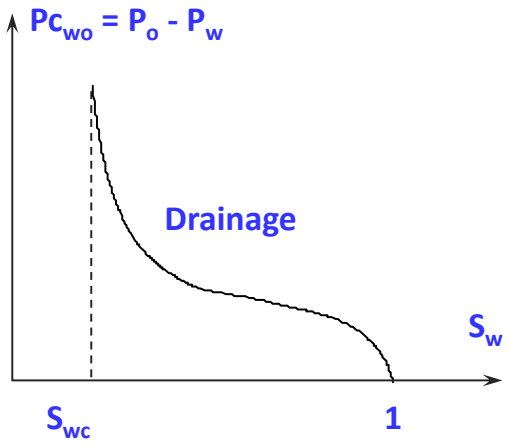
Po known everywhere

- **At WFL: Pc = 0 and then $Pw_{FWL} = Po_{FWL}$**

$$Pw = Pw_{ref} - \rho_w g Z$$

Pw known everywhere

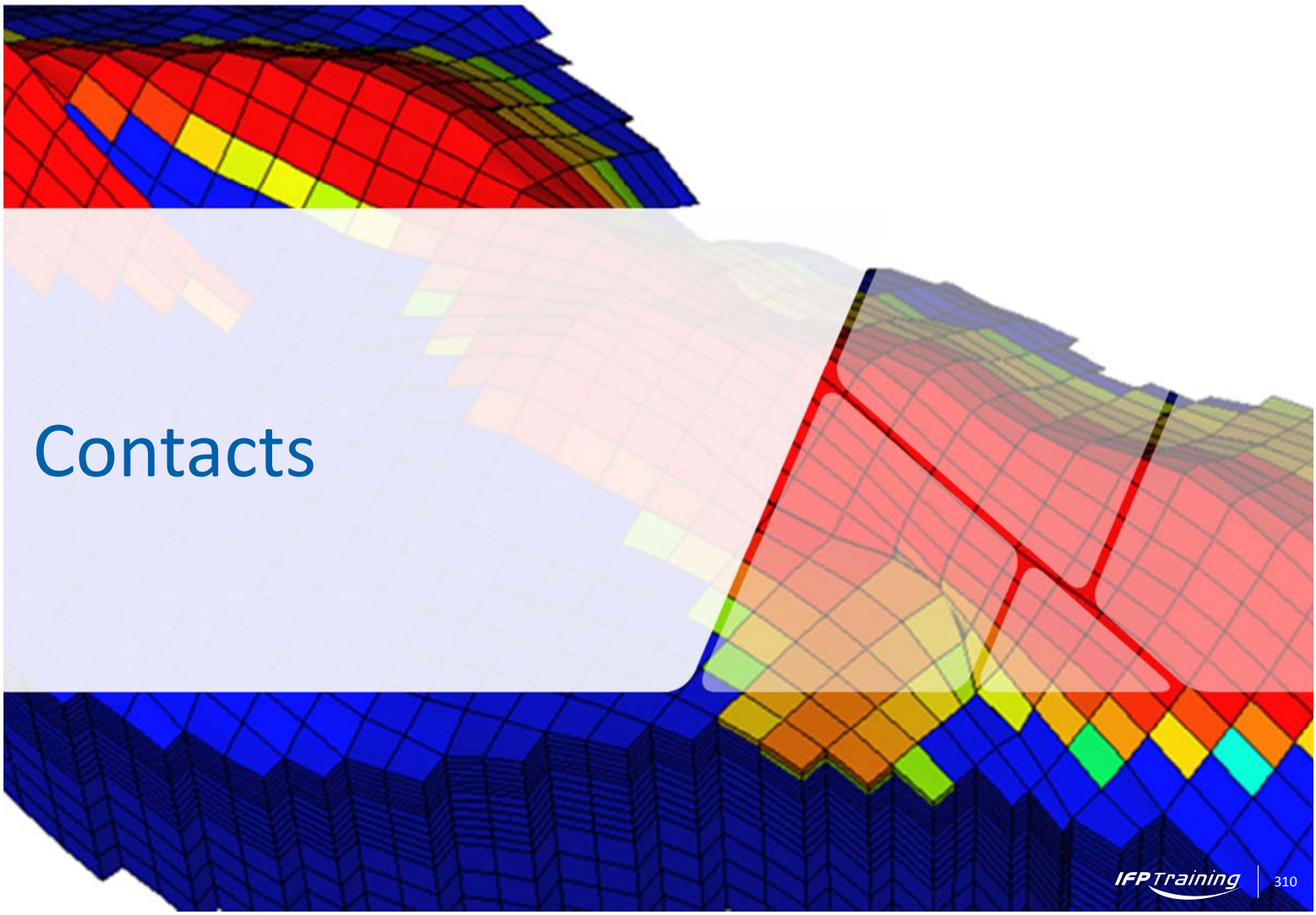
Initial state: saturation calculations



- **There is a gravity equilibrium in the transition zone**
  - In the water leg: $S_w = 1$
  - In the oil leg: $S_o = S_o\,(Pc_{wo})$ with $Pc_{wo} = P_o\,(z) - P_w\,(z)$
  - In the gas leg: $S_g = S_g\,(Pc_{go})$ with $Pc_{go} = P_g\,(z) - P_o\,(z)$
- **Saturations are calculated at the grid block center and are applied to the entire grid block**

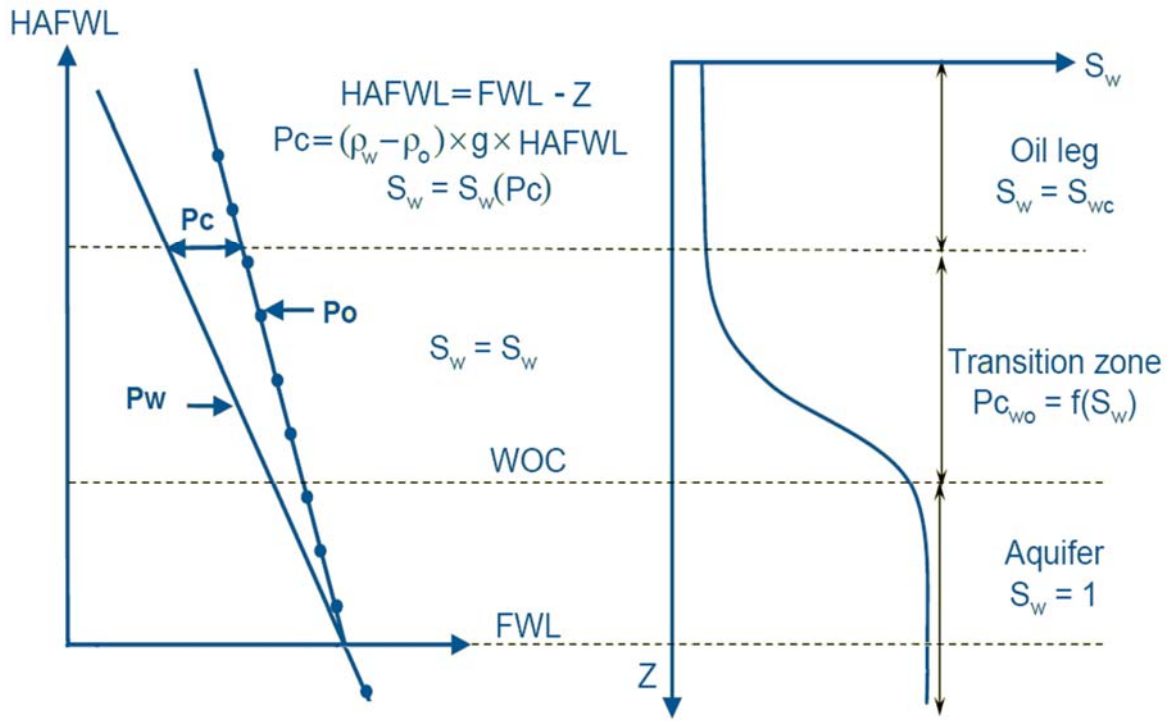
Example of the initial reservoir condition calculations

- **Goal:**
  - Compute pressure and saturation distribution everywhere within the reservoir model at the simulation start
- **Variables: pressure (P) and saturations (S)**
- **Example:**
  - Simple two-phase flow case oil/water
  - Initial data:
    - WOC
    - P @ reference depth z (datum)
  - Compute pressure distribution
  - Compute saturations

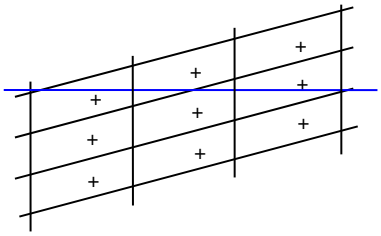


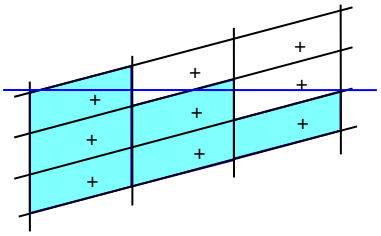
Contacts

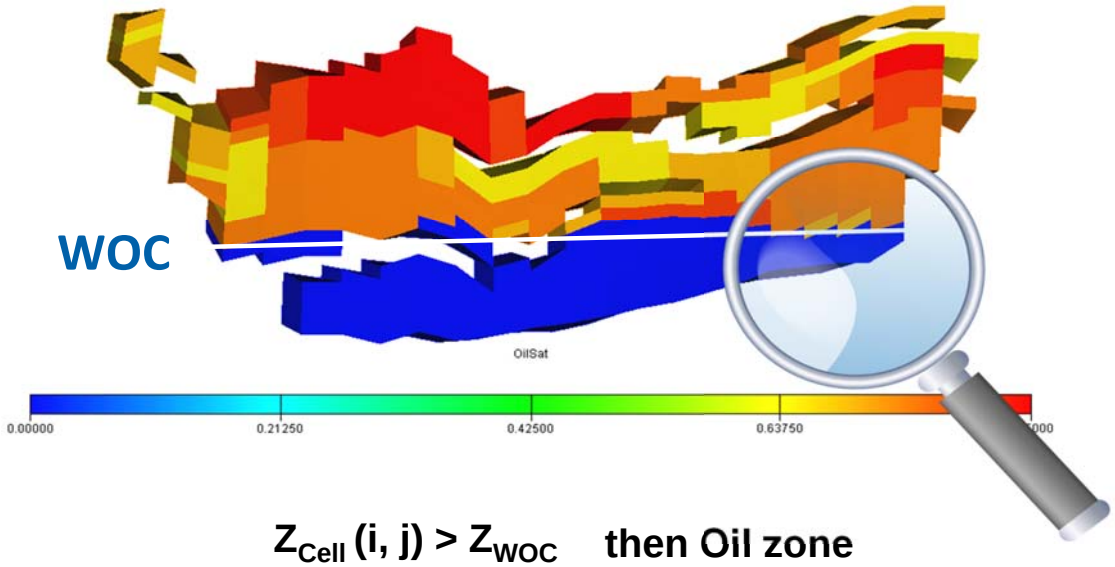
Initial state

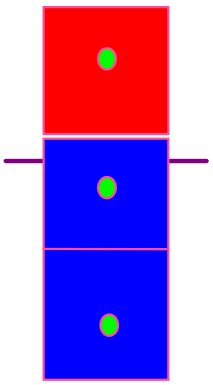


Contacts discretization









$Z_{Cell}\,(i, j) > Z_{WOC}$ **then Oil zone**

$Z_{Cell}\,(i, j) < Z_{WOC}$ **then Water zone**

Exercise

Given the following data for a reservoir (single rock type) containing oil and water only:

1. Calculate the height of the water-oil transition zone, assuming constant reservoir oil composition.

   Pressure at datum, Pi = 59 bar
   Bubble point pressure, Pb = 57 bar

Bo (Pi) = 1.1049	Bo (Pb) = 1.105	Bw (Pi) = 1.03	Rs = 32 v/v
Surface Densities:	ρ_o = 896 kg/m^3	ρ_w = 1059 kg/m^3	ρ_g = 0.9 kg/m^3

Sw	Pcow (bar) (drainage)	Pcow (bar) (imbibition)
0,11	0,6	0,6
0,20	0,2	0,15
0,30	0,1	0,04
0,40	0,09	0,0
0,50	0,08	-0,04
0,60	0,07	-0,1
0,70	0,06	-0,5
0,77	0,03	-1,0
1,0	0	

2. Calculate the height above the free water level at which the oil saturation is 50%.

Initial distribution

- **Several traps (non-communicating zones of the reservoir) can be defined. The use of several traps allows to take into account:**
  - distinct GOC and/or WOC
  - distinct Pb vs depth laws
  - distinct initial pressures

- **In the case of PVT traps:**
  - A complete PVT model (oil, gas and water characteristics) is affected
  - Pb vs depth curve, GOC, WOC and pressure at a given depth (datum) are given

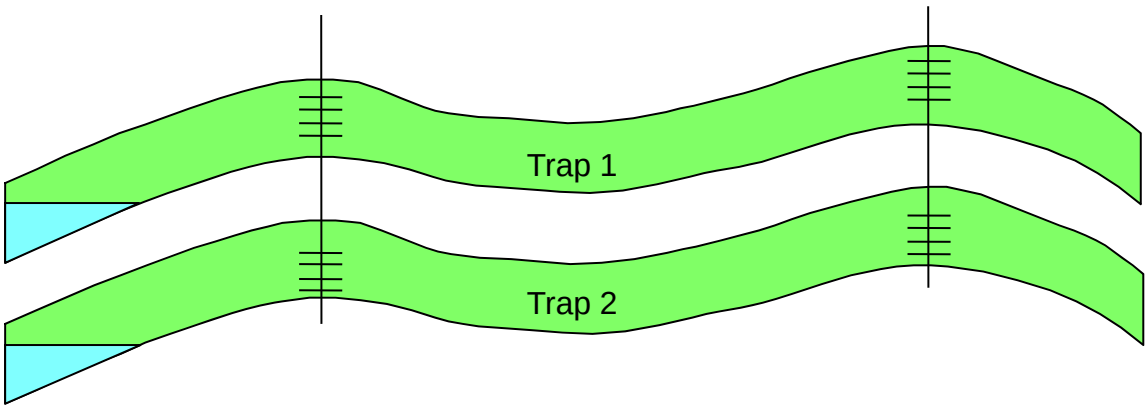
NB1 : initial pressure curve, Pb curve and GOC must be compatible

NB2 : knowing GOC and WOC depths and fluid densities, the simulator can calculate initial pressure vs depth curve.

Initial state with several traps

Multi layer reservoir example

- **A trap is defined as a set of cells in static equilibrium**
- **A trap is described by:**
  - Water-oil contact and a value of Pc_{wo} (WOC)
  - A gas-oil contact and a value of Pc_{go} (GOC)
  - An initial pressure at datum
- **A flow model can be initialized with one or several traps**



Multi layered reservoir with commingled completions

Key points to keep in mind

- **The initial state is correct when original volumes in place are correctly calculated**
- **Three main intervals can be defined:**
  - HC leg (Sw = Swc = Irreducible water saturation)
  - Transition zone (Swc < Sw < 1)
  - Water leg (Sw = 1)
- **The model initial equilibrium saturation distribution is established with drainage capillary pressure curves.**
- **Pressures changes at interface can be derived form Pc curves**
  - At the gas oil interface: Po (GOC) = Pg (GOC) - Pcgo (GOC)
  - At the water oil interface: Po (WOC) = Pw (WOC) + Pcwo (WOC)
- **In order to calculate the initial pressure, it is sufficient**
  - To give the pressure at a reference depth
  - The location of the contacts and the capillary pressures at the contacts
- **Several traps (non-communicating zones of the reservoir) can be defined.**



Dynamic reservoir simulation
Data review: Aquifers

IFP Training

Data review: aquifers

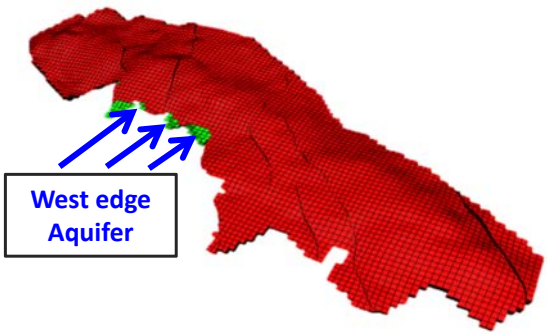
- Aquifer description 320
- Aquifer models 330

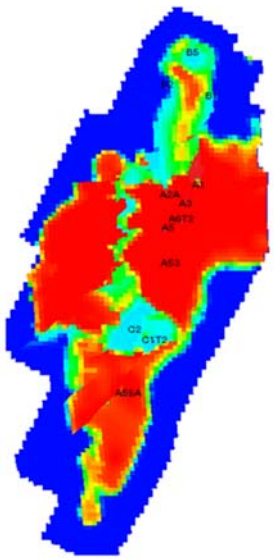
Aquifer description

Aquifer representation

Objectives

- to know cumulative water influx and pressure support versus time
- to approximate water influx by a model



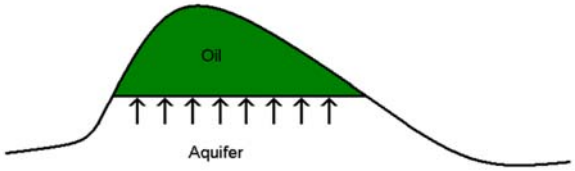


Aquifer representation

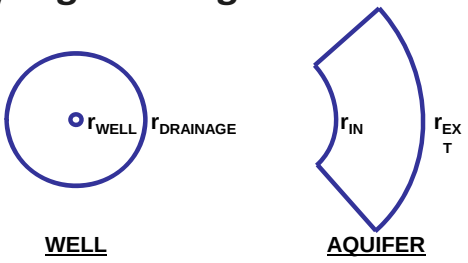
- **Objective is to estimate the aquifer activity, i.e. to estimate cumulative water influx and pressure support versus time**
- **These results depend on the following parameters:**
  - Vaq = Aquifer Volume
  - Ct = Aquifer Compressibility
  - Taq = Transmissivity between reservoir and aquifer
- **There are 3 possibilities to describe an aquifer:**
  1. Describe the entire aquifer with a large number of cells
  2. Use large grid cells
  3. Use Hurst & van Everdingen functions

Aquifer's configurations

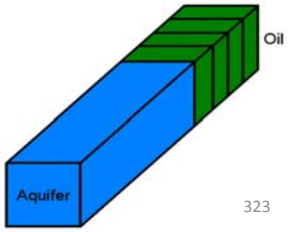
- **The bottom water drive aquifer: it is in contact with the entire hydrocarbon area. Water invasion occurring vertically is governed by the reservoir vertical permeability.**



- **The edge water drive aquifer: the water entries take place laterally. Horizontal permeability is governing the water mouvement.**

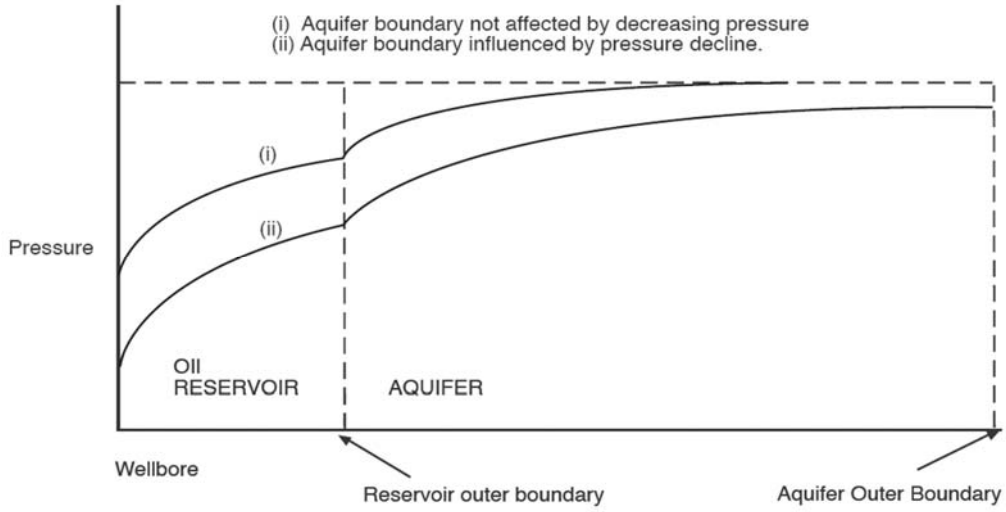


- **The linear water drive aquifer: it is a typical shape encountered in fluvio-deltaic deposition reservoirs (channels)**



Aquifer's representation

- **Water influx arises as a result of pressure changes decompressing the aquifer. If the pressure in an aquifer can be calculated, the resulting volumetric changes can be determined from the pressure/volume compressibility relationship.**
- **Pressure profile in a reservoir – aquifer system:**



Aquifer's representation

- **Cumulative water influx and pressure support versus time depends on the following parameters:**
  - Aquifer volume: Vaq
  - Aquifer compressibility: Caq
  - Transmissivity between reservoir and aquifer: Taq
- **There are two possibilities to represent aquifers**
  - Gridding aquifers
  - Numerical aquifers
  - Analytical aquifers

Main parameters

- **Aquifer expansion:**

$$\frac{dV_{aq}}{V_{aq}} = C_{aq} \cdot \Delta P_{aq}$$

- **Aquifer compressibility:**
  - Cp: pore compressibility
  - Cw: water compressibility

$$C_{aq} = C_p + C_w$$

- **Aquifer depletion:**

$$\frac{dV_{aq}}{dt} = -\frac{T^{ab}}{\mu_w} \cdot \left(P_{aq} - P_{res}\right)$$

$$\Delta P_{aq} = P_i - P_{aq} = P_i - P_{res} + \frac{T^{ab}}{\mu_w} \cdot \frac{dV_{aq}}{dt}$$

$$\Delta P_{aq} = \Delta P_{res} + \frac{T^{ab}}{\mu_w} \cdot \frac{dV_{aq}}{dt}$$

Aquifer's modeling

The diffusivity equation

- **The combination of the mass conservation law with Darcy law lead to the diffusivity equation:**

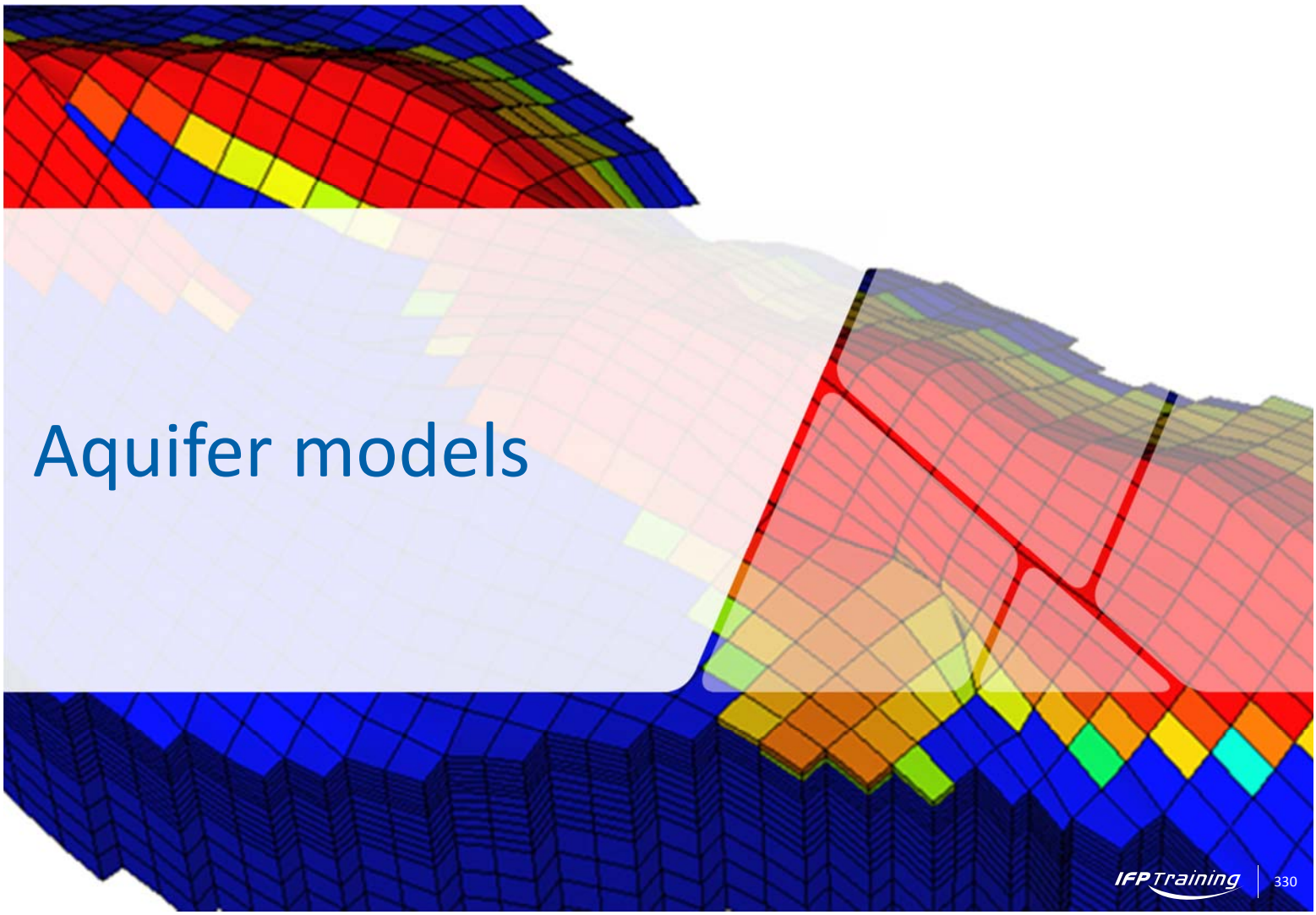
$$\left(\frac{\partial^2 P}{\partial r^2} + \frac{1}{r}\frac{\partial P}{\partial r}\right) = \phi \cdot C \cdot \frac{\mu}{k}\frac{\partial P}{\partial t}$$

- **Assumptions:**
  - Radial flow
  - Homogeneous isotropic porous medium, uniform thickness of the medium
  - Constant porosity and permeability (independent of pressure)
  - Fluid of small and constant compressibility, constant fluid viscosity
  - Small pressure gradient, gravity neglected (radial axis)

THE SOLUTION OF THE DIFFUSIVITY EQUATION DEPENDS ON INITIAL AND BOUNDARY CONDITIONS

Initial and boundary conditions

- **Initial condition: P = Pi @ t = 0 everywhere in the aquifer**
- **Inner boundary condition: the most commonly used,**
  - the constant terminal rate, P = f(t) i.e. used to establish build-up analysis
  - the constant terminal pressure, q = f(t) i.e. used to calculate water influx
- **Outer boundary condition:**
  - infinite aquifer, P = Pi as r → ∞
  - bounded aquifer, $\left(\frac{\partial P}{\partial r}\right)_{r_o} = 0 \quad no\ \ flow\ \ at\ \ r = r_o$



Aquifer models

Aquifer Representation

The usual boundary condition to grid is "No flow"

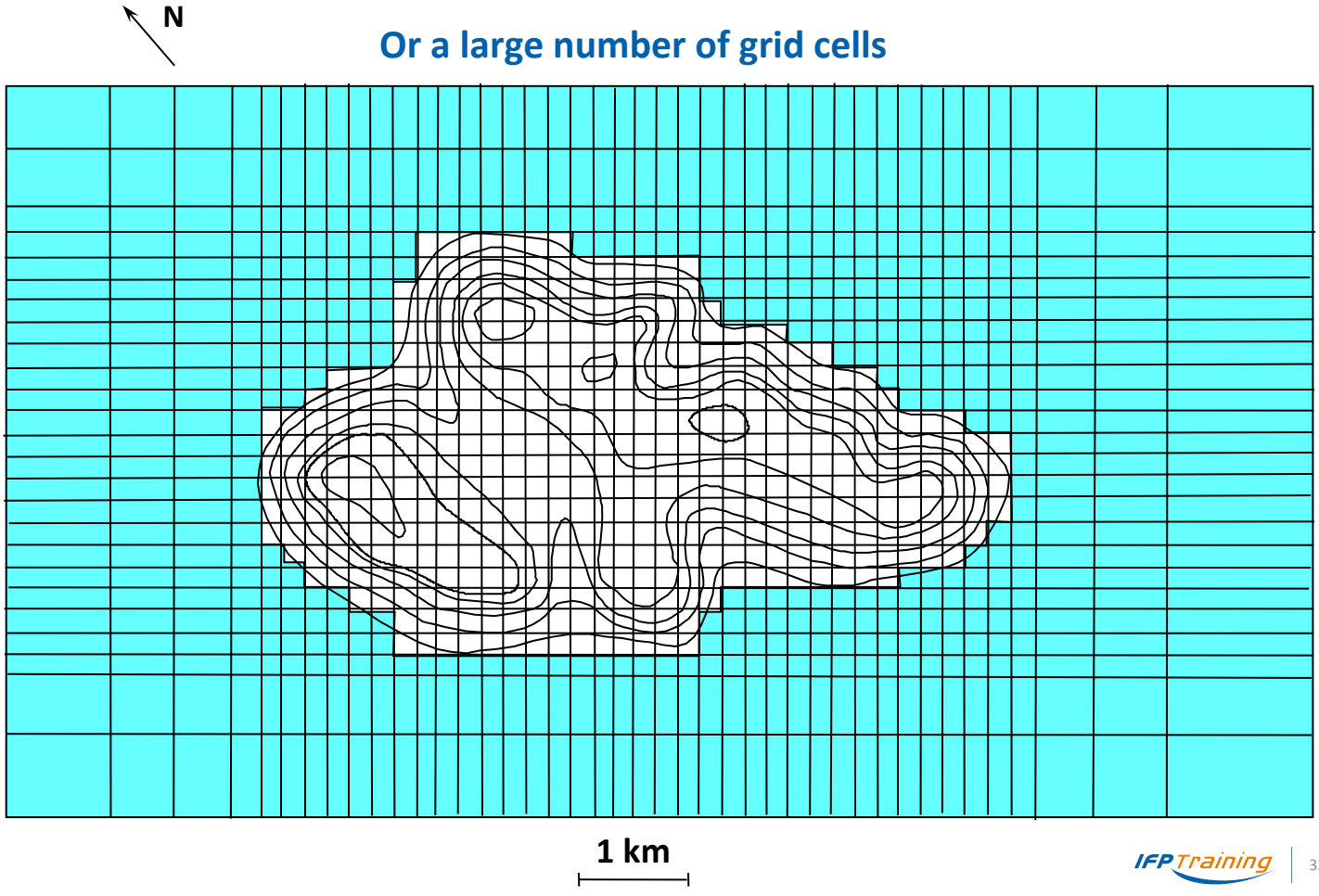


- **Three possibilities to describe the aquifer:**
  1. Describe the entire aquifer with a large number of cells
  2. Use large grid cells
  3. Use Hurst & van Everdingen functions.

Aquifer representation

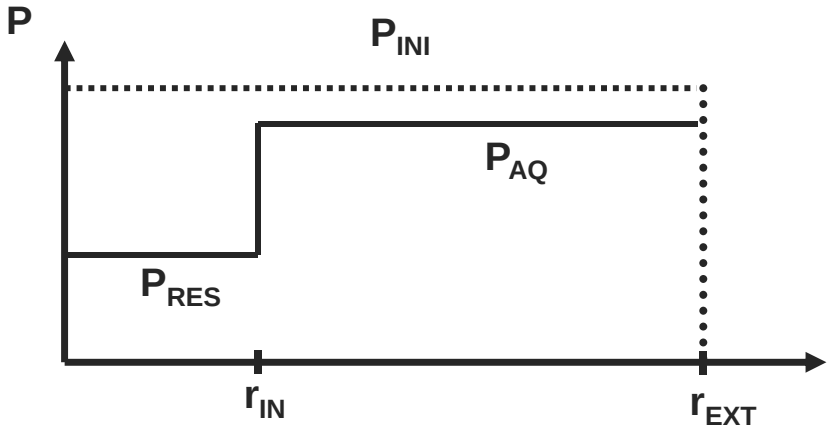
- **The usual boundary condition to grid is No-flow**
- **To represent the aquifer, the following possibilities exist:**
  - Grid the whole system (possibly with larger cells in the water zone, where lower precision is needed)
  - Take into account only a limited number of water cells in the WOC vicinity (one or a few rows) and multiply their pore volume (and correct their permeability if necessary)
  - Take into account only a limited number of water cells in the WOC vicinity (one or a few rows) and implement an analytical or numerical aquifer in these cells
- **The last two options allow for reducing drastically the total number of cells (they are usually the two options between which the engineer has to make a choice)**

Use of large grid cells



Numerical aquifers

- **Instantaneous expansion of a finite volume**
- **This is usually applied to small aquifers with closed boundaries and in equilibrium with the reservoirs.**
  - Qwi = C dP/dt
  - C = dV/dP
  - This is equivalent to a multiplied pore volume



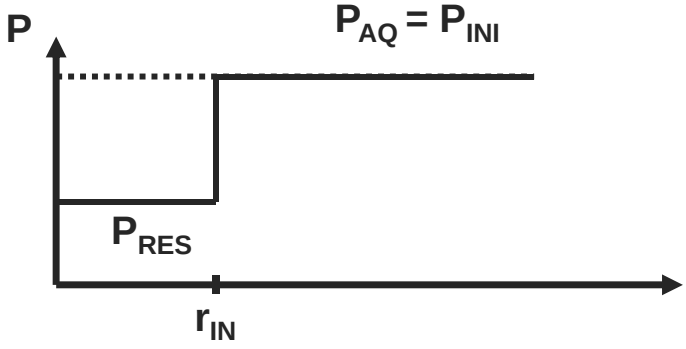
Analytical aquifers

Pseudo-steady state: Fetkovitch

- **The Fetkovich aquifer model uses a simplified approach based on a pseudo-steady state productivity index and a material balance relationship between the aquifer pressure and the cumulative influx.**
- **This model assumes that the pressure response is felt uniformly throughout the entire aquifer: the pressure at the outer boundary of the aquifer does not change.**
- **The aquifer inflow is modeled by the equation:**

$Q_{wi} = C\,(Pi - P)$

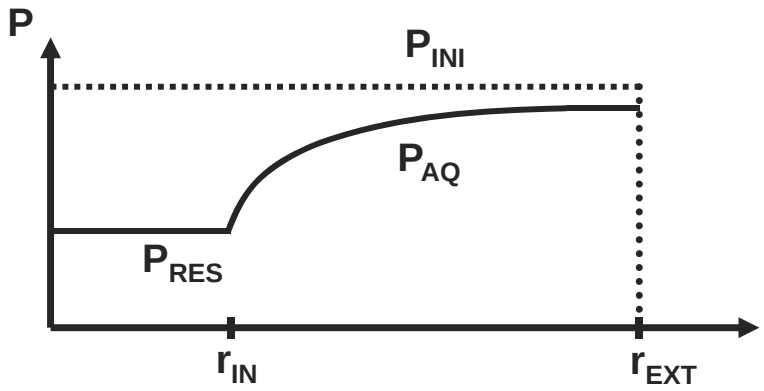
C: equivalent to a transmissibility
Pi: initial pressure in the gridblock i
P: pressure at time *t* in the gridblock i



Analytical aquifers - Transient Aquifer

- **All aquifers are finite in size, however there is a period of time when a pressure disturbance created by production from a well has not traveled far enough and reached the boundary of the aquifer.**

- **During this time the aquifer behaves as being infinite and unsteady state flow applies. After the boundary influences the behavior of the system and pseudo-steady state flow starts.**



Analytical aquifers

Transient aquifer: parameters

- **aquifer geometry**
  - net thickness
  - aquifer inner radius (radius equivalent to contact length)
  - ratio $r_{EXTERNAL}$ / r_{INNER} = ro/ri
  - encroachment angle (aperture)
- **petrophysics**
  - porosity
  - permeability
  - compressibility of water bearing rock
- **water**
  - compressibility of aquifer water
  - viscosity of aquifer water
- **external boundary condition**
  - condition at ro (constant pressure or no flow)

Radial aquifer model

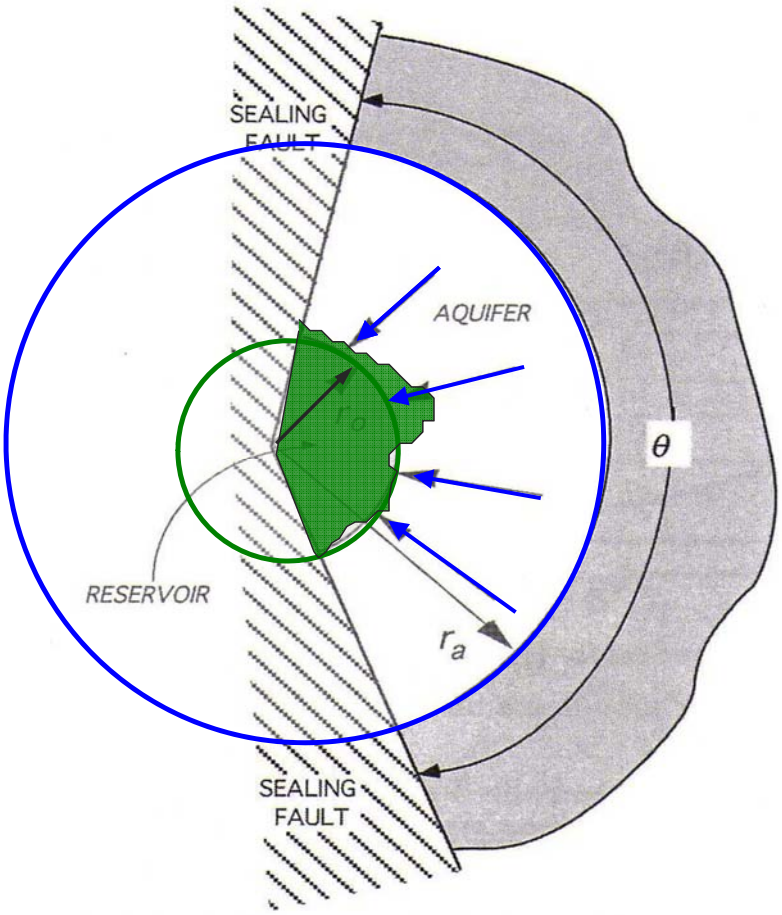
Hurst & Van Everdingen

Hurst and Van Everdingen solution is applicable to any reservoir where the flow into the reservoir is essentially radial in nature.

Hurst & Van Everdingen solutions are functions of:

- Dimensionless water influx and dimensionless time, as a function of dimensionless radius.

In well testing, the diffusivity equation is solved between the wellbore radius and the drainage radius, the same method will be used, but between the WOC radius and the external aquifer radius



Analytical aquifers

Transient aquifer: Carter-Tracy model

- **The Carter-Tracy aquifer model is a simplified approximation to a fully transient model, which refers to the diffusivity equation.**
- **The method uses tables that supplie a constant rate and a constant pressure influence function: Hurst & van Everdingen.**
- **Although the theory has been developed for a radially symmetric reservoir surrounded by an annular aquifer, the method is applicable to arbitrarily-shaped reservoirs.**

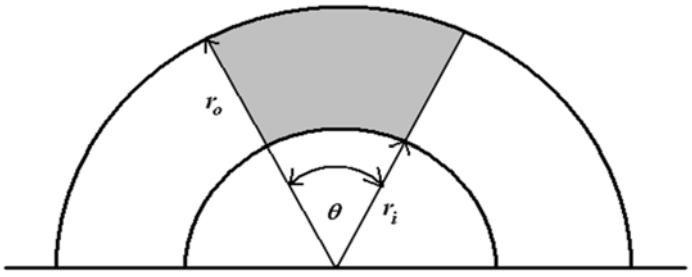
Carter-Tracy model: Boundary conditions

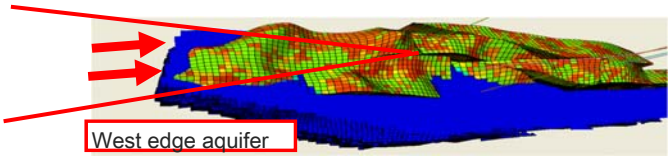
Two cases:

- **The Pressure case, where the pressure at the inside boundary is known and there is no flow at the outside boundary and we calculate the water influx.**

- **The Rate case, where the rate is known at the inside boundary. At the outside boundary there is no flow and we calculate the total pressure drop.**

Carter Tracy model: parameters





Water influx: $We = f(r_o/r_i, \theta, k.h, \phi.h.C)$

r_o: **outer radius**

r_i: **inner radius**

θ: **encroachment angle**

k: **permeability**

ϕ: **porosity**

h: **thickness**

C: **compressibility**

Carte Tracy: dimensionless parameters

- **The two main parameters that govern the behavior of the aquifer are:**
  - the dimensionless time:

$$t^* = \frac{k \cdot t}{\mu_w \cdot \phi \cdot C \cdot r_i^2}$$

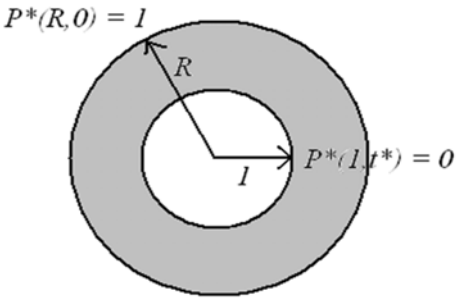
k	aquifer permeability
f	aquifer porosity
µw	water viscosity in the aquifer
C	compressibility
ri	outer radius of the reservoIR

  - the aquifer influx constant:

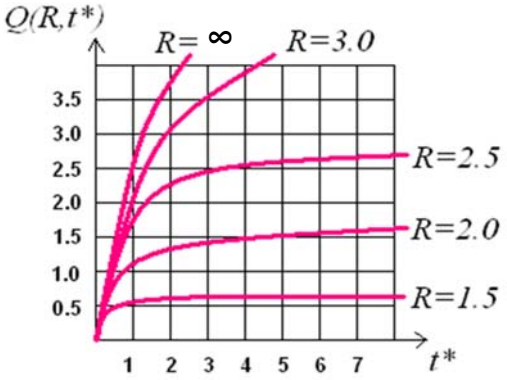
$$U = h \cdot \theta \cdot \phi \cdot C \cdot r_i^2$$

h	aquifer thickness
q	aperture

Carte Tracy: constant pressure case



$Q_R(t^*) = We(t)/2\pi$

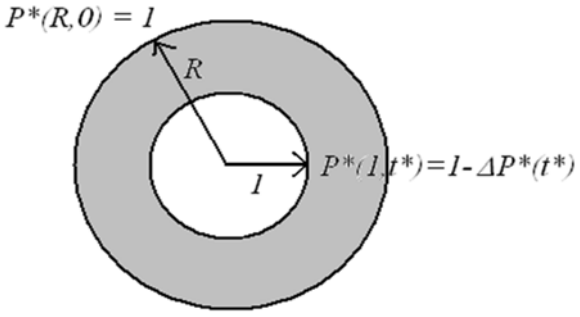


outer radius: R **permeability:** 1
inner radius: 1 **porosity:** 1
aperture: 2π **thickness:** 1
compressibility: 1

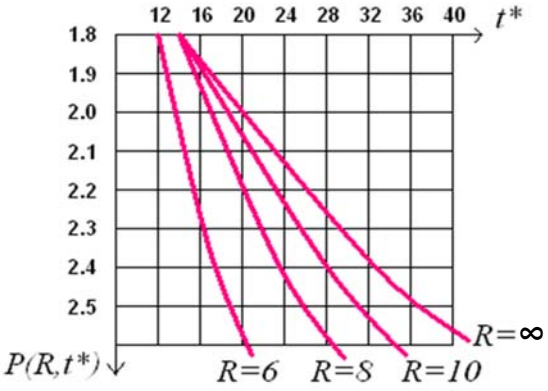
$$We = \theta \cdot \phi \cdot h \cdot C \cdot r_i^2 \cdot \Delta P \cdot W_D(t^*)$$
$$We = U \cdot \Delta P \cdot W_D(t^*)$$

Analytical aquifers

Carte Tracy: constant rate case



$$P_R(t^*) = 2\pi\,\Delta P^*(t^*)$$



outer radius: R **permeability:** 1
inner radius: 1 **porosity:** 1
aperture: 2π **thickness:** 1
compressibility: 1

$$P(R,t^*) = P(\infty,t^*) + \frac{q\cdot\mu_w}{2\cdot\theta\cdot k\cdot h}\cdot Ei\left(-\frac{1}{4\cdot t^*}\right)$$

Key points to keep in mind

- **Gridding the aquifer?**
  - Time and memory consuming
- **Porosity "increase" of the last cell row (or consider a CLOSED aquifer)?**
  - All the water is located at the same distance
  - What increase of Pore Volume?
  - How to correct permeability?
- **Introduce STEADY-STATE aquifer?**
  - Only applicable to very particular cases corresponding to constant Pressure (close outcropping, drastic change in permeability, partially sealing fault…)
- **Use "transient" aquifers?**
  - Reproduce the propagation phenomenon
  - Physical parameters (identical to the reservoir ones except for external radius)

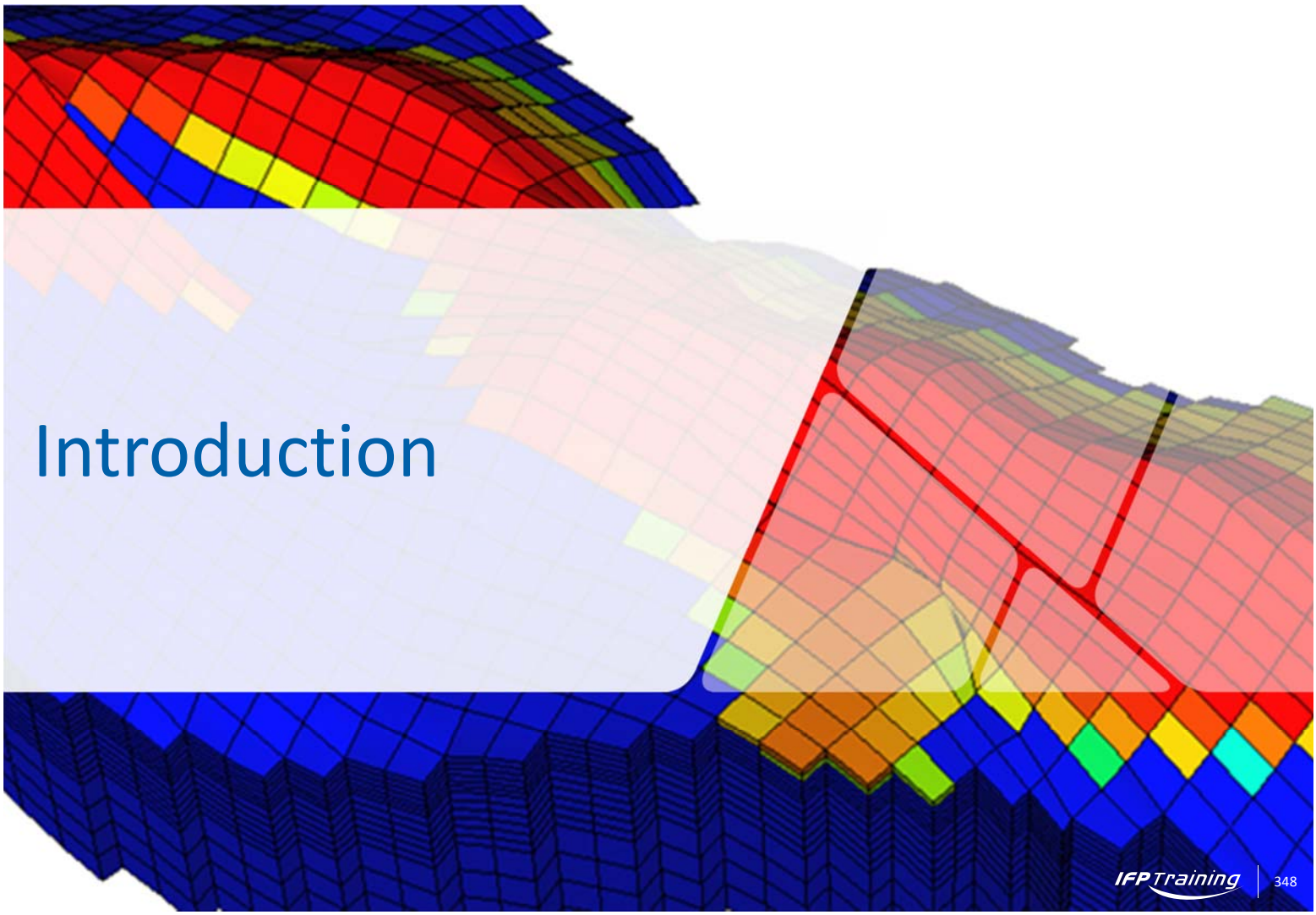


Dynamic reservoir simulation
Data review: Flow description

IFP Training

Sommaire

- Introduction 348
- Flow description – one phase 352
- Flow description – multiphase 370
- Hysteresis 390
- Options in reservoir simulation 402

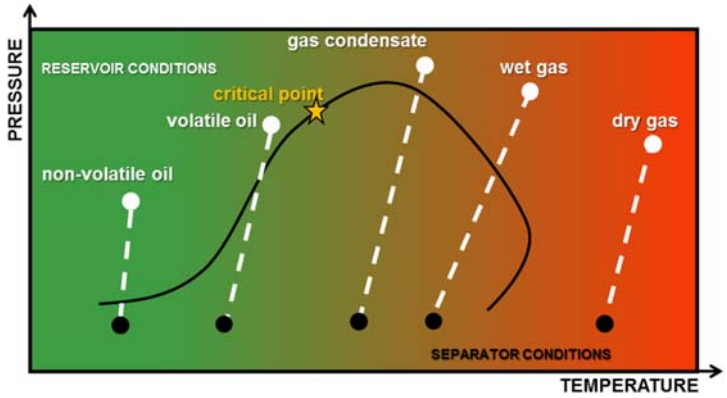


Introduction

Displacement in production monophase or multiphase flow

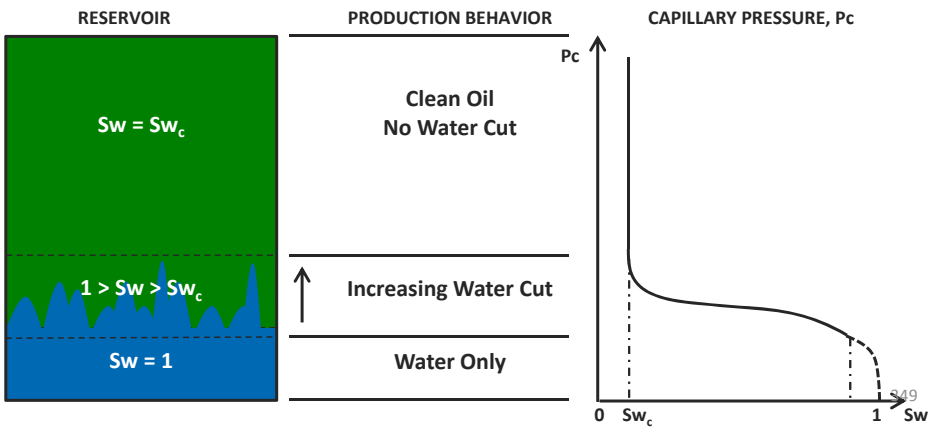
Reservoir fluid – PVT:

- **Mono phase:**
  - Undersaturated oil
  - Wet gas (above dew point)
  - Dry gas
- **Multiphse:**
  - Saturated oil
  - Gas condensate (below dew point)



Reservoir zones:

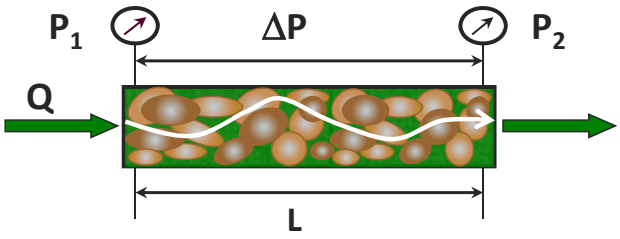
- **Mono phase:**
  - Oil leg
  - Water leg – aquifer
- **Multiphase**
  - Transition zone



Permeability definition

Dimensions

- **Measures the capacity and ability of the formation to transmit fluids**



$$k = \frac{Q\mu}{A} \times \frac{L}{P_1 - P_2}$$

1 Darcy; Q: cm³/sec; μ: 1 cp = $\frac{1}{100} \times \frac{\text{dyne} \times \text{sec}}{\text{cm}^2}$; L: cm; A: cm²; $P_1 - P_2$: 1 atm = 1.033 kg/cm²

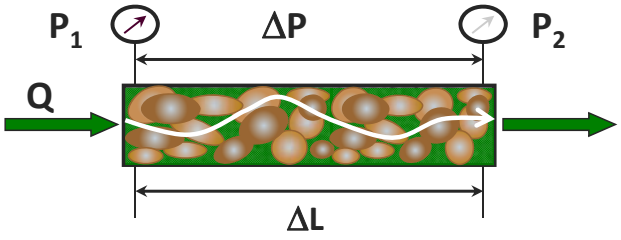
Darcy's Law

μ:	Fluid Viscosity (cP)
ΔP:	Differential Pressure (atm)
A:	Cross sectional area (cm²)
Q:	Injection flow rate (cm³/s)
L:	Length (cm)

Relative permeability

- **Darcy Law in monophasic fluid flow**

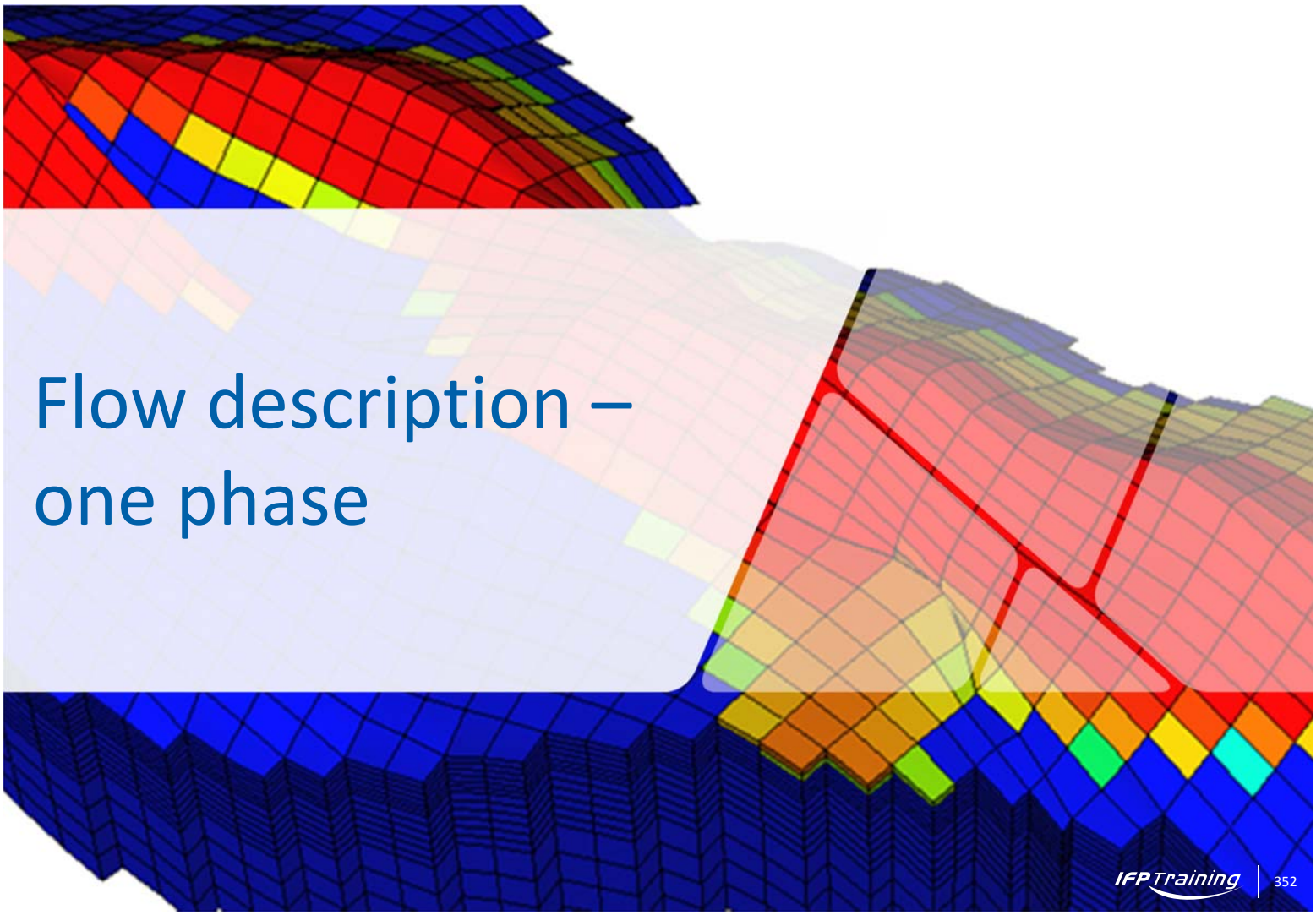
$$Q = -K \cdot \frac{A}{\mu \cdot \Delta L} \cdot \Delta P$$



- **Darcy Law in multiphase fluid flow**

$$Q_o = -\frac{k_o A}{\mu_o} \cdot \frac{\Delta P_o}{\Delta L} \qquad Q_w = -\frac{k_w A}{\mu_w} \cdot \frac{\Delta P_w}{\Delta L} \qquad kr_o = \frac{k_o}{K}$$

- K = absolute permeability (m² for SI, mD for PFU unit systems)
- ko = effective permeability to oil (same units as K)
- kro = relative permeability to oil (no dimension)



Flow description – one phase

Monophasic permeability

- **Single phase flows are modelled with Darcy 's law:**

$$U = -\frac{k}{\mu}\,\mathrm{grad}\,\Phi = -\frac{k}{\mu}\left(\frac{dP}{dx} - \rho\, g\,\frac{dz}{dx}\right)$$

- **Permeability K is independent from the fluid**
- **Laboratory measurements are done on plugs which are extracted horizontally or vertically from cores. Experience shows that Kv is not equal to Kh**
- **Gas and oil flow with connate water in the reservoir**

Permeability dimension

$$[K] = [U] \,.\, [\mu] \,/\, [dP/dx]$$

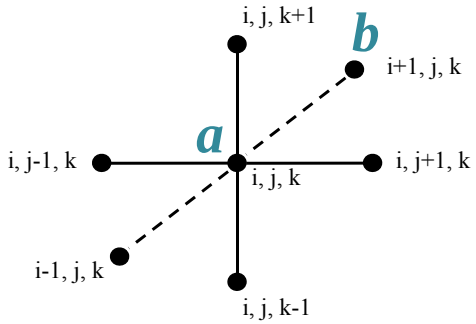
$$[K] = [L\,T^{-1}] \,.\, [M\,L^{-1}\,T^{-1}] \,/\, [M\,L^{-2}\,T^{-2}]$$

$$[K] = [L^2]$$

Permeability has the dimension of a surface

Flow calculations between cells

Transmissivity



$$[T^{ab}] = [Q^{ab}] \,.\, [\mu \,/\, [P^{ab}]$$

$$[T^{ab}] = [L^3\,T^{-1}] \,.\, [M\,L^{-1}\,T^{-1}] \,/\, [M\,L^{-1}\,T^{-2}]$$

$$[T^{ab}] = [L^3]$$

Transmissivity has the dim *ension of a volume.*

$$T = K\,\frac{A}{L}$$

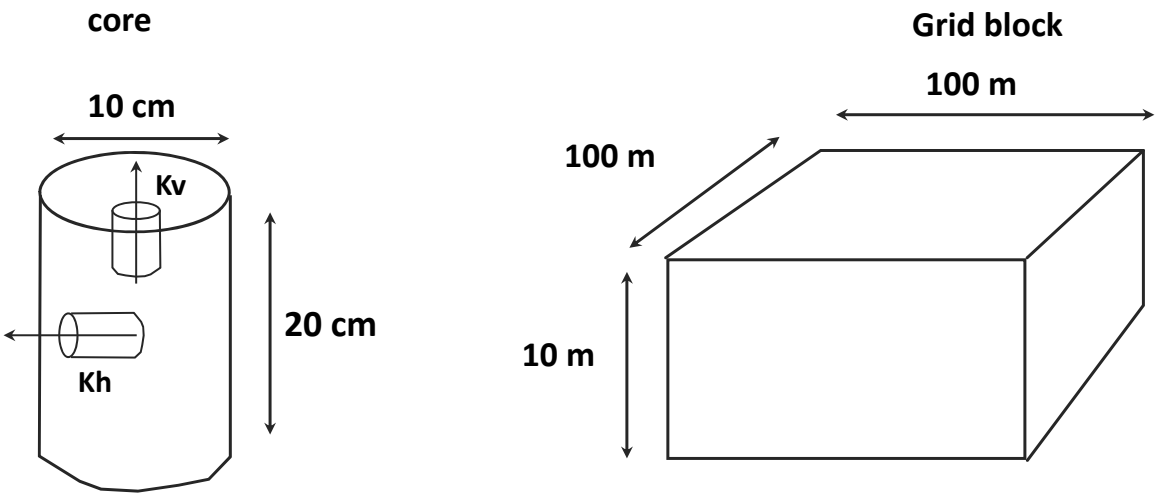
K : *reservoir permeability*

A : *surface open to flow*

L : *length of flow path*

$$Q^{ab} = -\,(T^{ab} / \mu\,)\,(\Delta P - \rho\, g\, \Delta z)$$

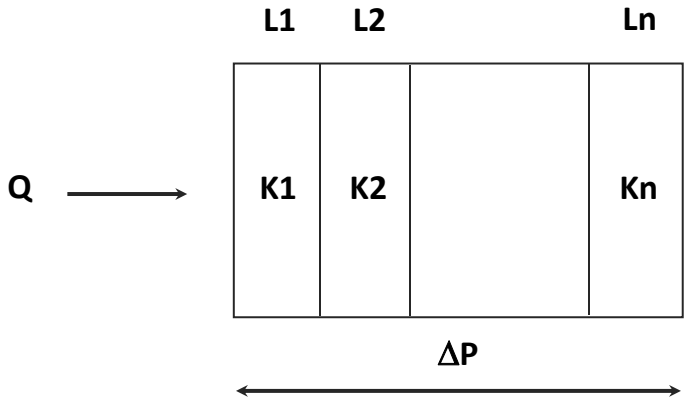
From core to flow model



Single phase flow: problems to solve

- **Permeability composition**
  - Problem: how to represent a permeability distribution by a constant permeability when the flow path is known
  - Solution: arithmetic average, harmonic average, power law…
- **Permeability homogenization**
  - Problem: how to represent a permeability distribution by a constant permeability when the flow path is unknown
  - Solution: fine scale model, history match…
- **Permeability modelling**
  - Identification of basic laws (e.g.: Phi – K laws)
  - Well blocking & Upscaling of basic laws
  - Population of cells
  - Quality checks

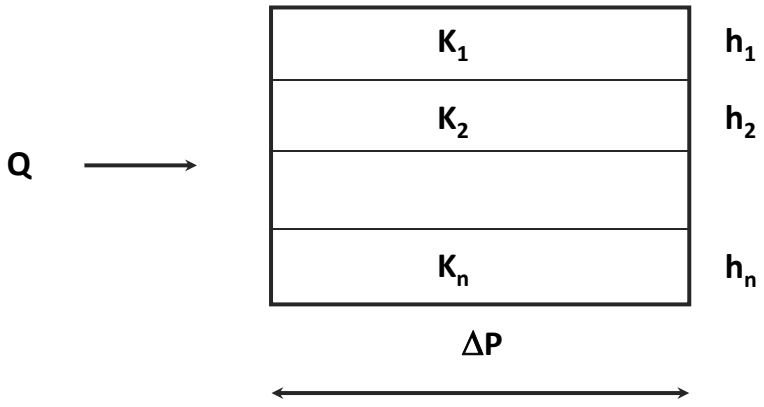
Permeability composition: serial flow



$$\Delta P = \Sigma \Delta P_i = \Sigma (Q \mu L_i / K_i h)$$

$$L / K = \Sigma (L_i / K_i)$$

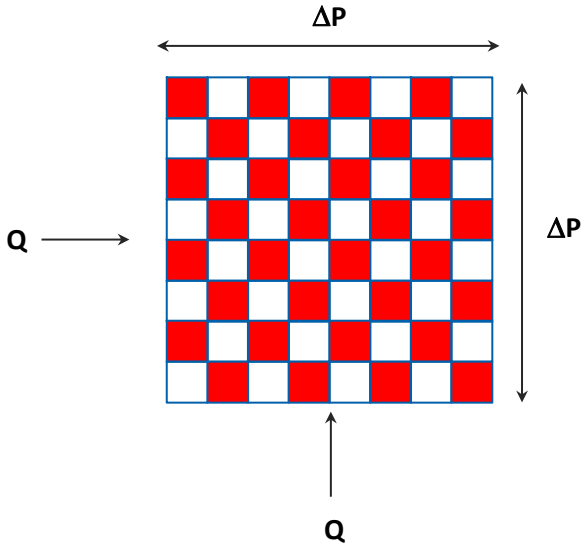
Permeability composition: parallel flow



$$Q = \Sigma Q_i = \Sigma (K_i h_i / \mu) . \Delta P / L$$

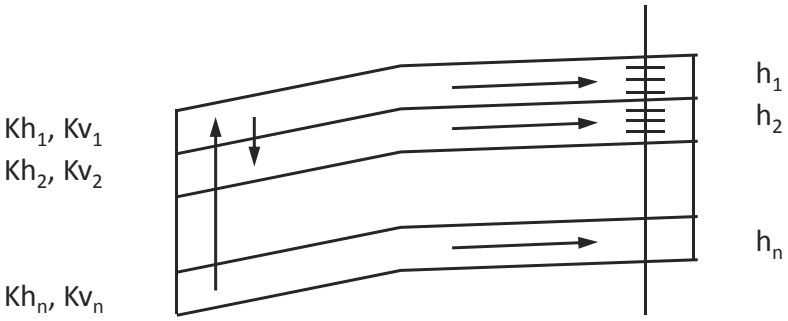
$$K H = \Sigma K_i h_i$$

Permeability composition: random isotropic flow



$$Ln\ K = \Sigma\ pi\ Ln\ Ki$$

Permeability composition: horizontal & vertical flows



Vertical flow
=
1D flow

$H / Kv = \Sigma\ h_i / Kv_i$

Horizontal flow
=
Parallel flow

$Kh\ H = \Sigma\ Kh_i\ h_i$

Permeability composition: power law

- **Average permeability is calculated as follows:**

$$K^{\omega} = \sum p_i K_i^{\omega}$$

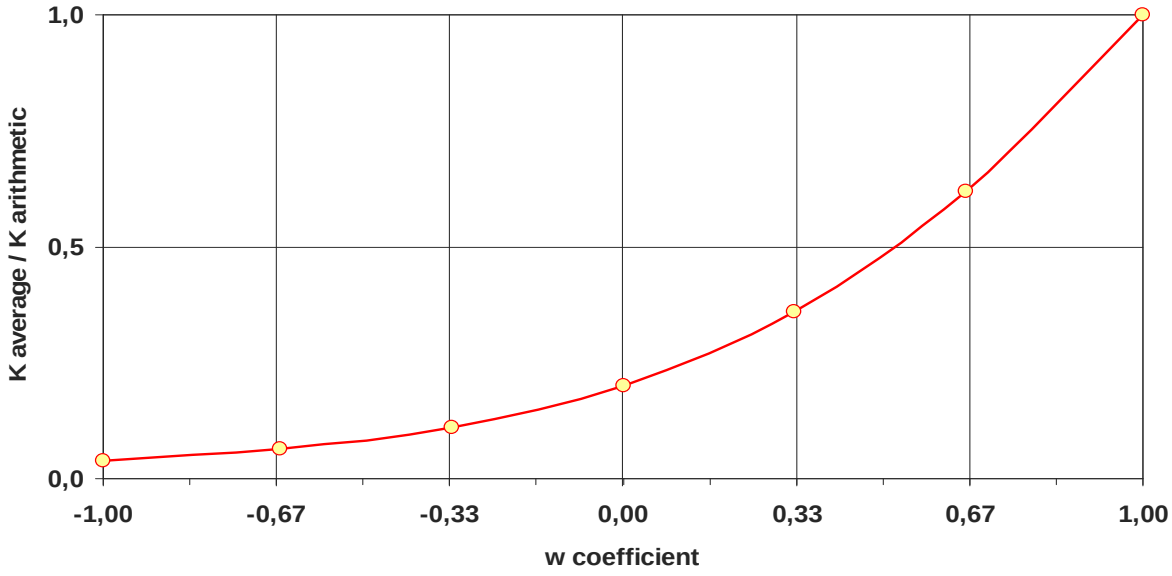
- **This is an extension of harmonic, geometric & arithmetic means:**
  - w = -1: harmonic mean
  - w = 0: geometric mean
  - w = 1: arithmetic mean
- **Coefficient w is related to the type of flow**
  - w = -1: serial flow
  - w = 0: random isotropic flow
  - w = 1: parallel flow

Permeability composition: power law

ω = -1
harmonic mean
serial flow

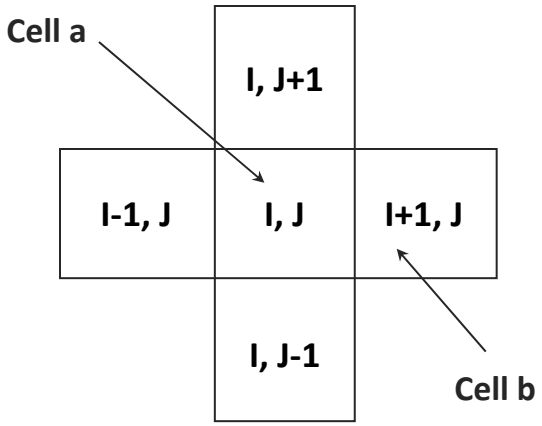
ω = 0
geometric mean
random flow

ω = 1
arithmetic mean
parallel flow



This is one example of composition, the shape of the curve depends on the K distribution

Permeability composition: transmissivity calculations

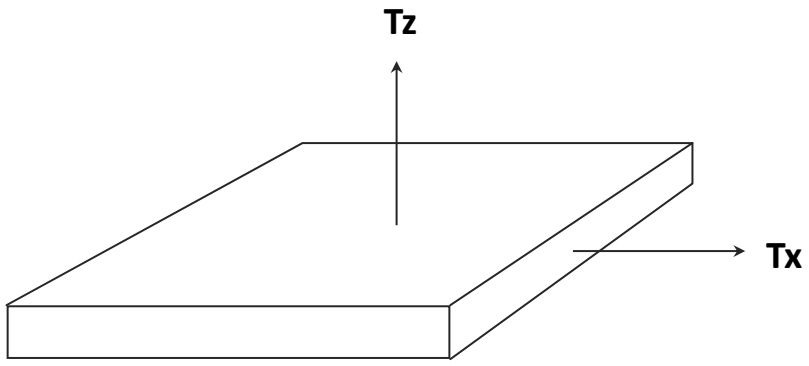


$$Tx^{ab} = \frac{2\,Kx^{a}\,Kx^{b}}{Kx^{a} + Kx^{b}} \frac{\Delta y \Delta z}{\Delta x}$$

$$Ty^{ab} = \frac{2\,Ky^{a}\,Ky^{b}}{Ky^{a} + Ky^{b}} \frac{\Delta x \Delta z}{\Delta y}$$

$$Tz^{ab} = \frac{2\,Kz^{a}\,Kz^{b}}{Kz^{a} + Kz^{b}} \frac{\Delta x \Delta y}{\Delta z}$$

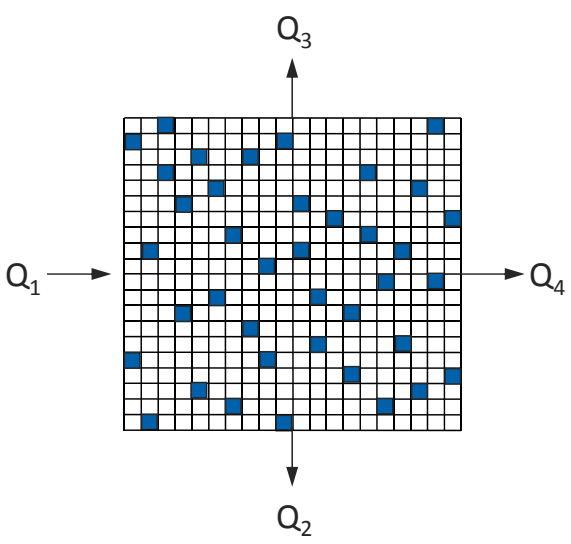
Permeability composition: transmissivity calculations



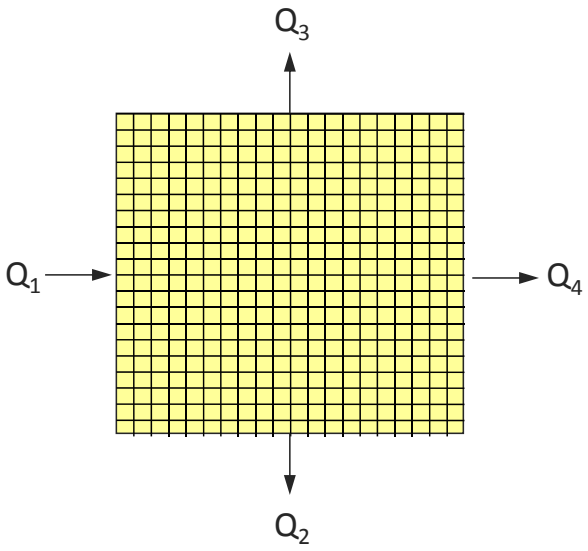
For a regular grid and a homogeneous reservoir:

$Tz / Tx = (Kz / Kx) / (Dz / Dx)^2$

Permeability homogenization: principles



HETEROGENEOUS CELL



HOMOGENEOUS CELL

Permeability homogenization: some results

- **Cardwell & Parsons (1945)**
  - Hypothesis
    - K is a random function
  - Results
    - Upper & lower limit for K* derived from K distribution
- **Matheron (1966)**
  - Hypothesis
    - K is an isotropic random function
  - Results
    - K* derived from flow dimension, K harmonic & arithmetic means
- **Begg & King**
  - Hypothesis
    - Reservoir is composed of sands (constant K) and impermeable shales
  - Results
    - K* derived from K and shale distribution

Permeability homogenization: Matheron formula

- **Hypothesis**
  - Reservoir is infinite & isotropic
  - Flow dimension (1D, 2D, 3D) is known
  - K distribution is known
- **Results**
  - Equivalent permeability depends on flow dimension, K harmonic & arithmetic K means

$$k^* = \frac{N-1}{N} A(K) + \frac{1}{N} H(K)$$

$$A(K) = \sum p_i k_i$$

$$H(K) = 1/\sum \frac{p_i}{k_i}$$

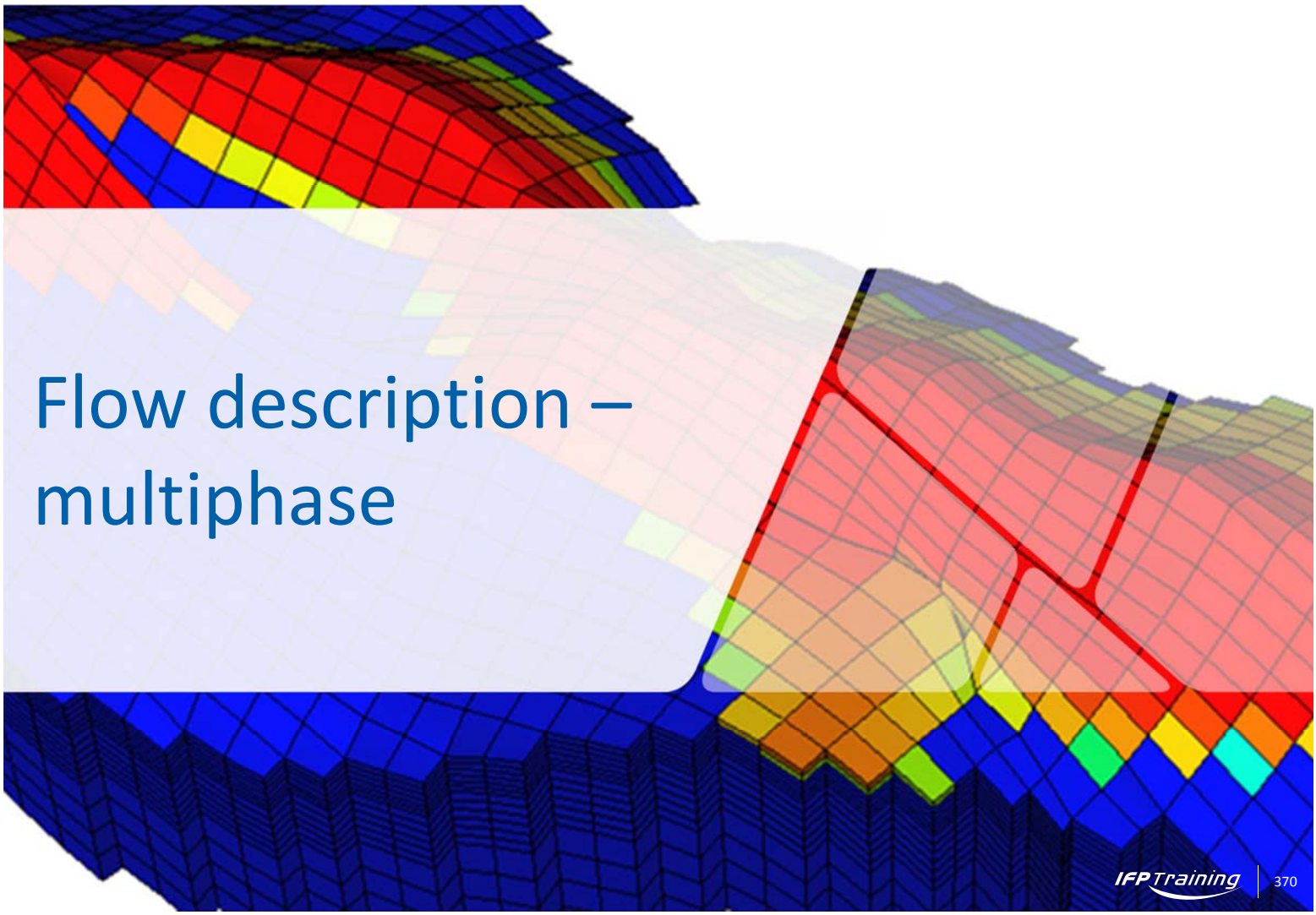
  - Matheron formula respects the range H(k) < K* < A(K)

Key points to keep in mind

- **Single phase flows are modelled with Darcy ’s law**

Problems:

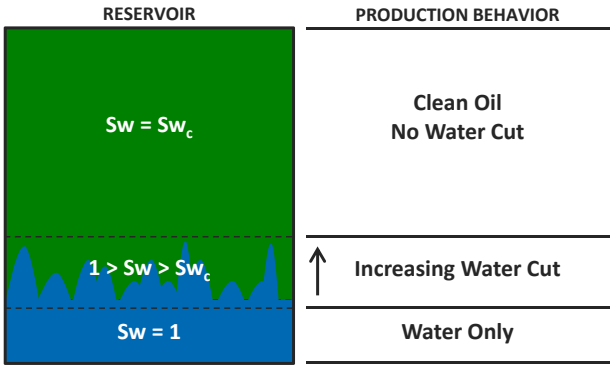
- **Permeability composition: how to represent a permeability distribution by a constant permeability when the flow path is known**
- **Permeability homogenization: how to represent a permeability distribution by a constant permeability when the flow path is unknown**
- **Permeability modelling: Identification of basic laws, upscaling of basic laws…**

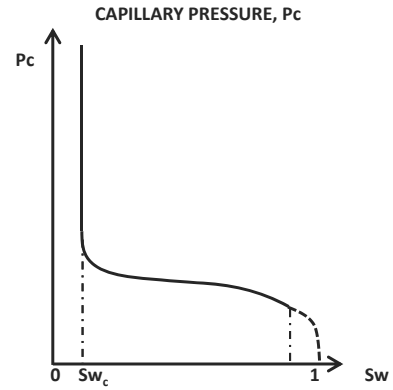


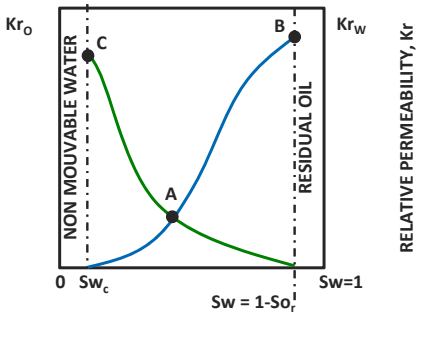
Flow description – multiphase

Displacement in Production

- **The displacement will depend on:**
  - Relative permeabilities
  - Oil and water viscosity







A. Oil and water flow at equal ease.

B. Residual oil saturation (**Sor**), this oil cannot be recovered by water flooding.

C. Non movable water saturation (**Swc**) characteristic for a specific rock.

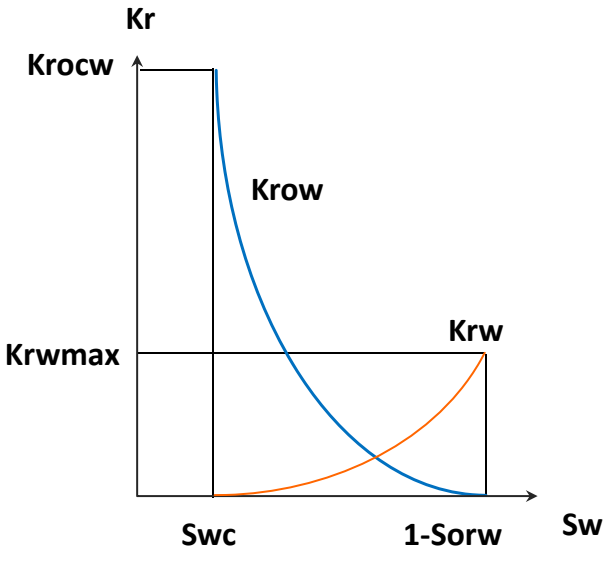
Multiphase flow description

- **Polyphasic flows are modeled with the following equations:**
  - Ug = - K (Krg / μg) grad Φg
  - Uo = - K (Kro / μo) grad Φo
  - Uw = - K (Krw / μw) grad Φw

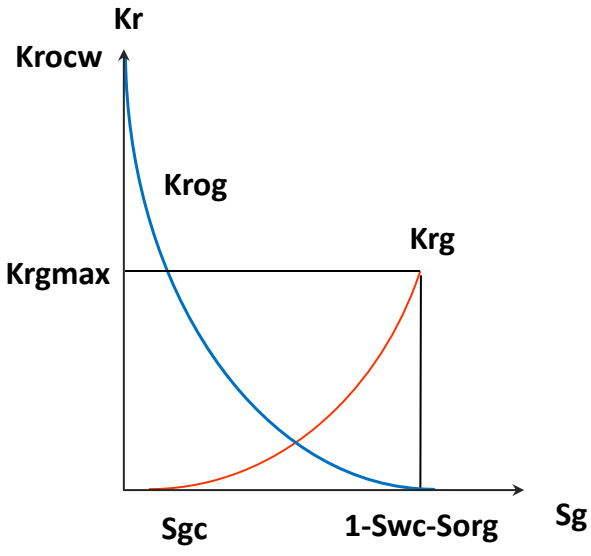
- **Relative permeability curves measured in the laboratory are based on 1D – two phase flow (water/oil or gas/oil)**

Multiphase flow

Relative permeability curves



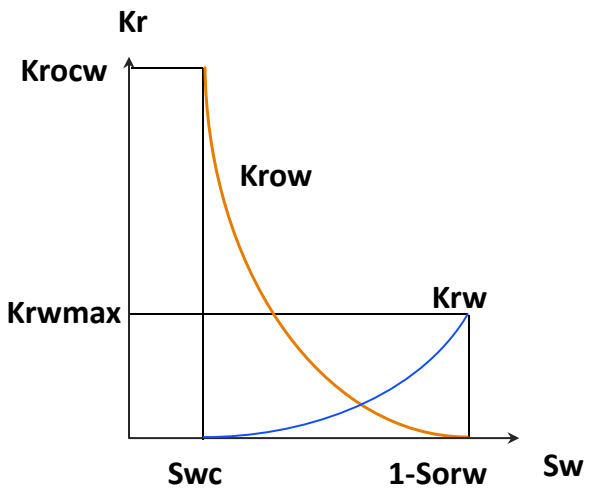
WATER-OIL

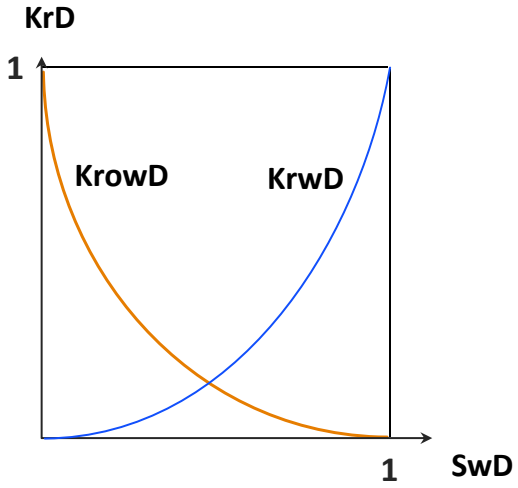


GAS-OIL

Multiphase flow

Relative permeability normalization

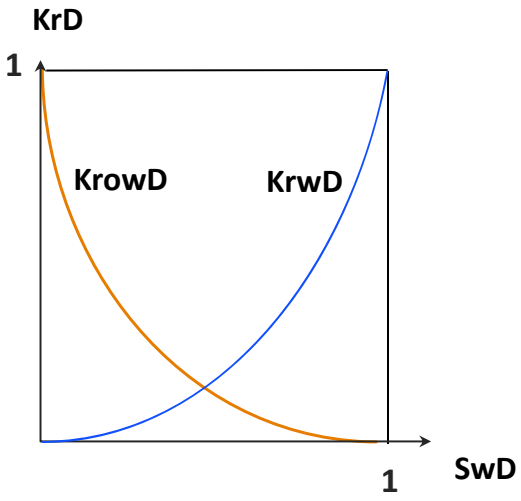


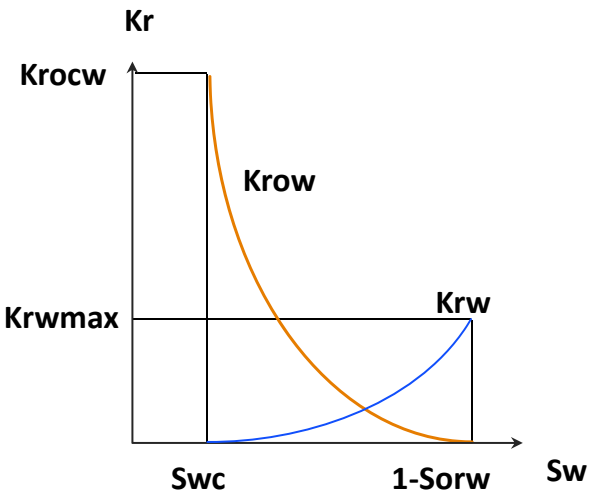


$$SwD = \frac{Sw - Swc}{1 - Swc - Sorw} \qquad KrwD = \frac{Krw}{Krwmax} \qquad KroD = \frac{Kro}{Kromax}$$

Multiphase flow

Relative permeability normalization

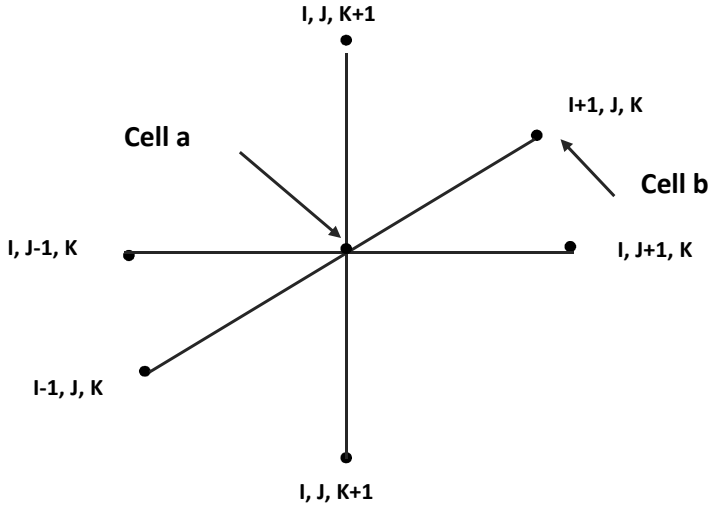




Sw = SwD (1-Swc-Sorw) + Swc
Kro = KroD . Kromax
Krw = KrwD. Krwmax

Multiphase flow

Calculations between cells



- Monophasic flow: $Q^{ab} = - (T^{ab} / \mu) . (\Delta P - \rho g \Delta z)$
- Polyphasic flow: $Q_i^{ab} = - (T^{ab} Kr_i^{ab} / \mu_i) . (\Delta P_i - \rho_\iota g \Delta z)$

Multiphase flow calculations

Use of upstream saturation

1. **Pressures and saturations are defined at the grid cell centre**

2. **Flows are calculated per phase:**
   - $Q_q = - (k . A / \Delta x) . M_g . (\Delta P_g - \rho_g . g . \Delta z)$
   - $Q_o = - (k . A / \Delta x) . M_o . (\Delta P_o - \rho_o . g . \Delta z)$
   - $Q_w = - (k . A / \Delta x) . M_w . (\Delta P_w - \rho_w . g . \Delta z)$

3. **For each phase, the flow direction is defined by the potential gradient between two grid cell centres. The phase mobility is calculated using the upstream saturation**

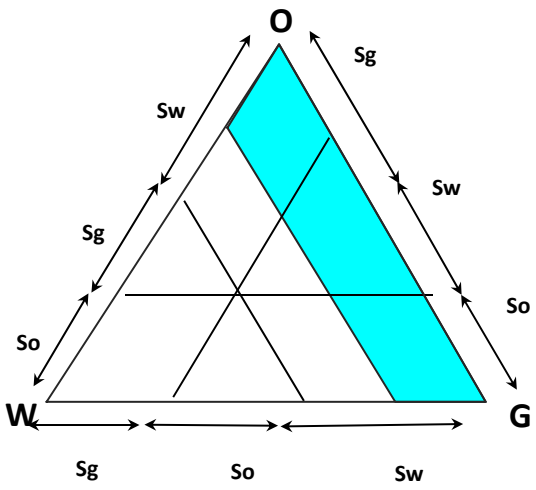
Problems to solve

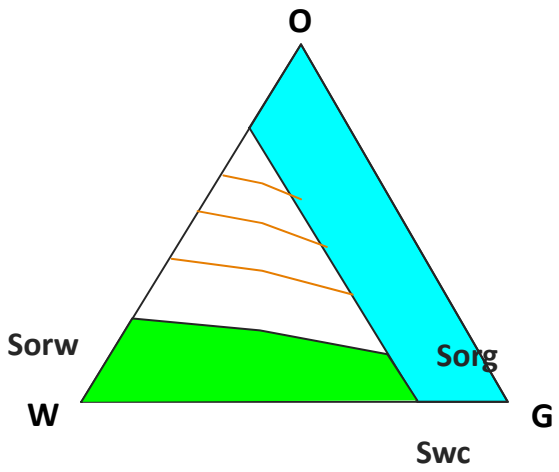
- **Three phase relative permabilities**
  - How to represent a three phase flow with two phase rel perms
- **Homogenization**
  - How to represent an heterogeneous porous medium by an equivalent homogeneous porous medium.
- **Pseudoization**
  - How to represent a fine gridded homogeneous porous medium by an equivalent coarse gridded homogeneous porous medium.

Three phase relative permeabilities

- **Three phase flow are not usually performed in laboratory conditions**
- **Three phase relative permeability are calculated using water-oil relative permeability (Krw,Krow) and gas-oil relative permeability (Krg,Krog)**
- **It is generally admitted:**
  - Three phase Krw = Krw (Sw)
  - Three phase Krg = Krg (Sg)
  - Three phase Kro = Kro (Sw,Sg)

Three phase flow: ternary diagram





Three phase relative permeabilities: channel flow theory

- There is at most only one mobile fluid in any flow channel
- The wetting phase is located primarily in the small pore spaces, the non wetting phase in the large pore spaces, and the intermediate phase spatially separates them
- At equal water saturations, the microscopic fluid distributions at the water oil interface are identical in a water-oil system and in a three phase system: Krw and Pcwo are identical in the three phase and two phase systems
- At equal gas saturations, the microscopic fluid distributions at the gas oil interface are identical in a gas-oil system and in a three phase system: Krg and Pcgo are identical in three phase and two phase systems

Three phase relative permeability: Stone 1 model

$$kr_o = \frac{S_o^* \,.kr_{ow}.kr_{og}}{kr_{owmax}.(1-S_w^*).(1-S_g^*)}$$

- **Normalized fluid saturations:**

$$S_w^* = \frac{S_w - S_{wc}}{(1 - S_{wc} - S_{om})} \qquad S_o^* = \frac{S_o - S_{om}}{(1 - S_{wc} - S_{om})} \qquad S_g^* = \frac{S_g}{(1 - S_{wc} - S_{om})}$$

S_{om} = minimum value of the residual oil saturation

$$S_{om} = S_{orw} - \frac{S_{orw} - S_{org}}{1 - S_{wi} - S_{org}} \cdot S_g$$

- **Impedance factors of oil flow:**

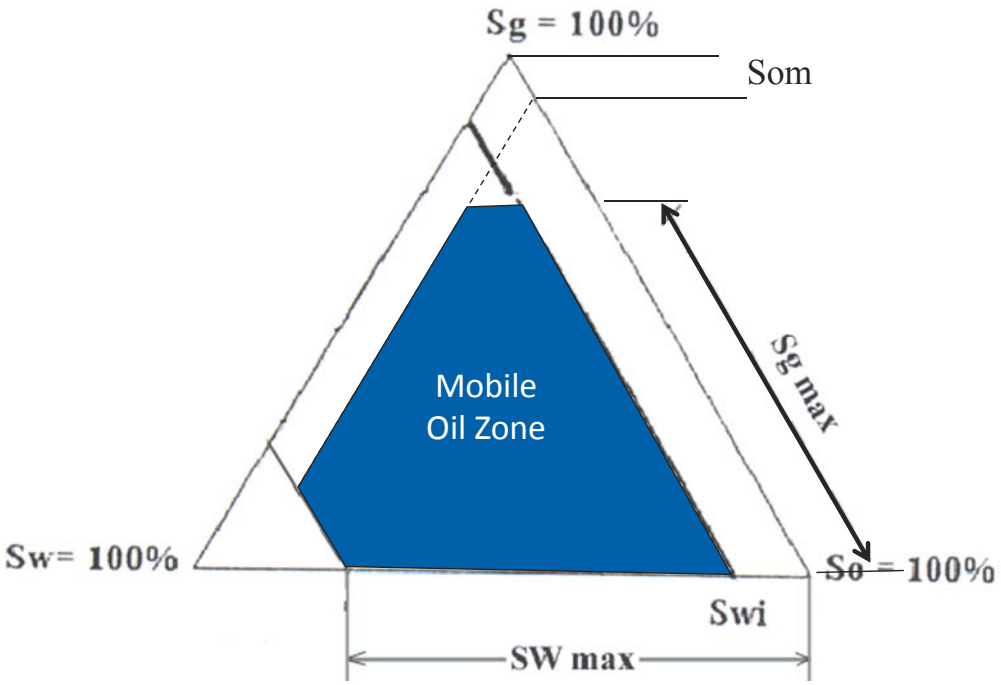
$$Kr_{ow} = \beta_{ow}\left(1 - S_w^*\right) \qquad Kr_{og} = \beta_{og}\left(1 - S_g^*\right)$$

- **Impedance of oil flow by water and gas are two independent events:**

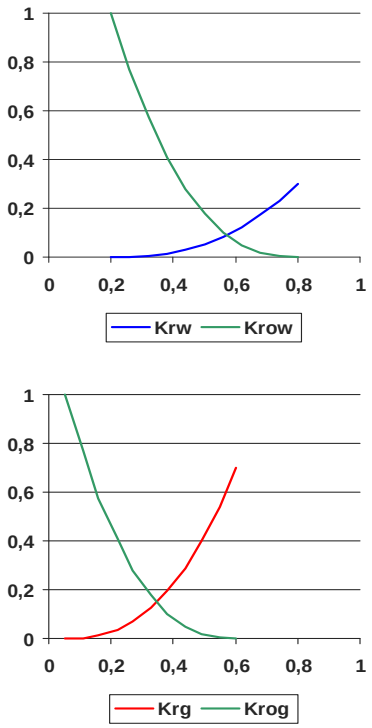
$$Kr_o = \beta_{ow}\,\beta_{og}\,S_o^*$$

Three phase relative permeability

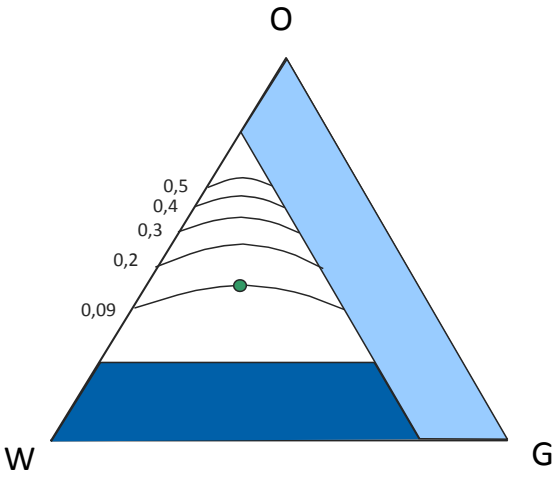
Ternary diagram for isoperm representation (Stone I)



Three phase relative permeability: Stone 1 (example)



Geometrical construction



Swc = 20%
Sorw = 20%

Sgc = 5%
Sorg = 15%

Three phase relative permeability: Stone II

$$kr_o = \max\left(0, kr_{ow\,max}\left\{\left(\frac{kr_{ow}}{kr_{ow\,max}} + kr_w\right)\cdot\left(\frac{kr_{og}}{kr_{og\,max}} + kr_g\right) - (kr_w + kr_g)\right\}\right)$$

- krow(Sw) and krog(Sg) are computed from the 2 phase flow kr since the third fluid is absent So = 1-Sw or So = 1-Swi-Sg
- Som is not computed
- kro may be negative, in this case kro = 0

Three phase relative permeability: Other models

- **Stone-Dietrich model:**

$$kr_o = \frac{1}{kr_{ow\max}}\left[kr_{ow}(S_w) + kr_w\right]\left[kr_{og}(S_g) + kr_g\right] - \left[kr_w + kr_g\right]$$

identical to Stone II if krowmax = 1

- **Baker model I:**

weighted interpolation with the saturations

$$kr_o = \frac{S_g kr_{og}(S_o) + (S_w - S_{wi})kr_{ow}(S_o)}{S_g + S_w - S_{wi}}$$

krow and krog are computed with So=1-Sw-Sg

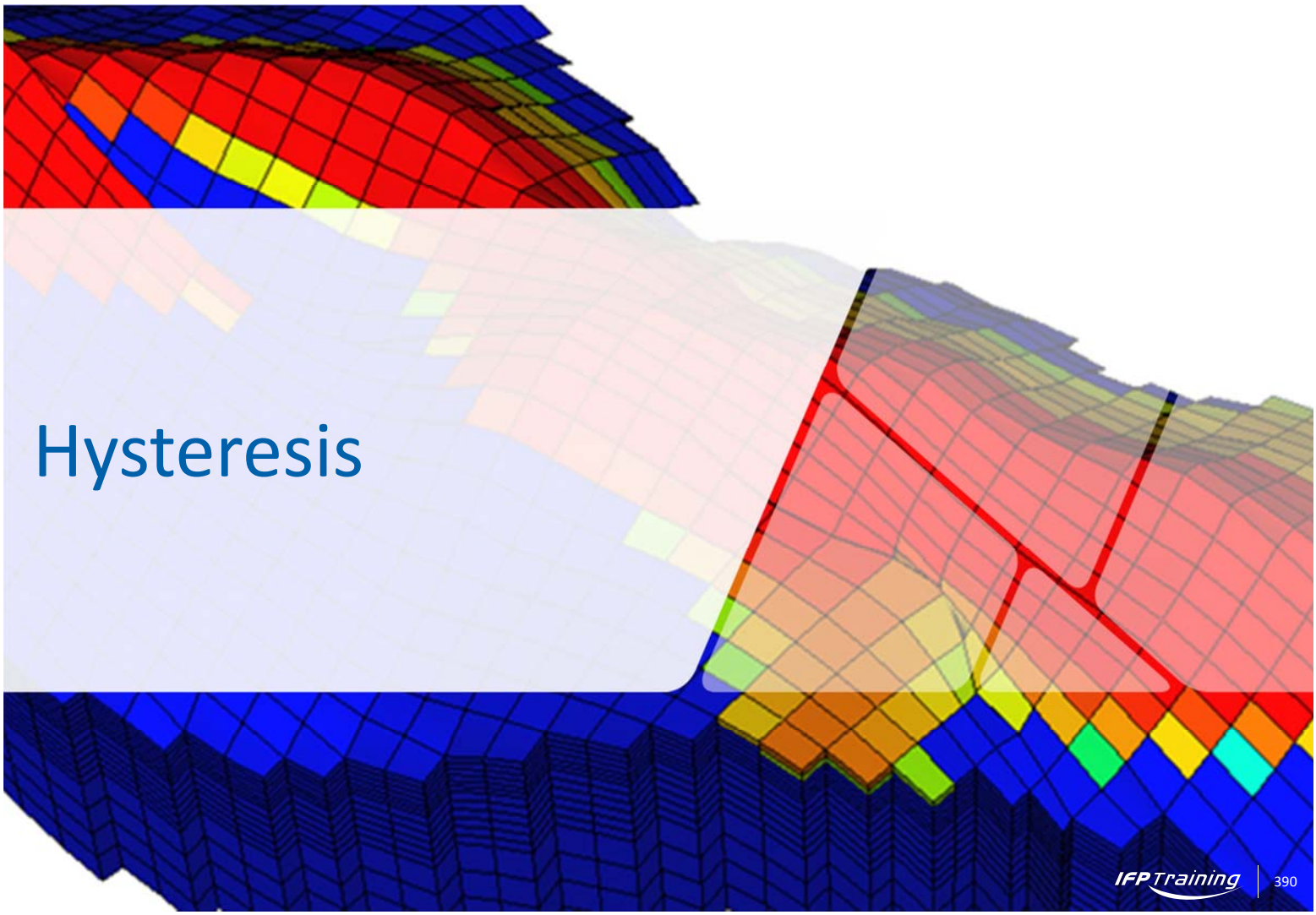
Three phase relative permeability

Comparison

- **Stone's model II underestimates kro and leads to non physical solutions for small values of So**
  - trapping of oil: Som > max(Sorw, Sorg)
  - or, on the contrary, Som = 0 (mainly if pseudo)
- **Stone's model I avoids the non physical solutions but needs the knowledge of Som. Overestimation of kro for small values of So**
- **Baker's model I generates non linear isoperm if Sorw and Sorg are very different**
- **All models except the geometrical construction diverge for the small So. The final recovery is biased.**

Key points to keep in mind

- **Relative permeability**
  - Allows to generalize Darcy's law to multiphasic flows in the reservoir
  - Is defined by a curve as a function of saturation, typically $\mathbf{k_{ro}(S_w)}$ and $\mathbf{k_{rw}(S_w)}$
- **Relative permeability curves**
  - Depend on wettability
  - Rule flow of fluids (water and hydrocarbons) in the reservoir and have a strong influence on the Recovery Factor
  - Are measure in laboratory in 1D and two-phase flow
- **Three phase relative permeabilities are calculated through models:**
  - Stone 1, Stone 2
  - Stone-Dietrich
  - Baker
  - Etc…
- **Models are based on normalized fluid saturations, water-oil relative permeability (Krw,Krow) and gas-oil relative permeability (Krg,Krog)**



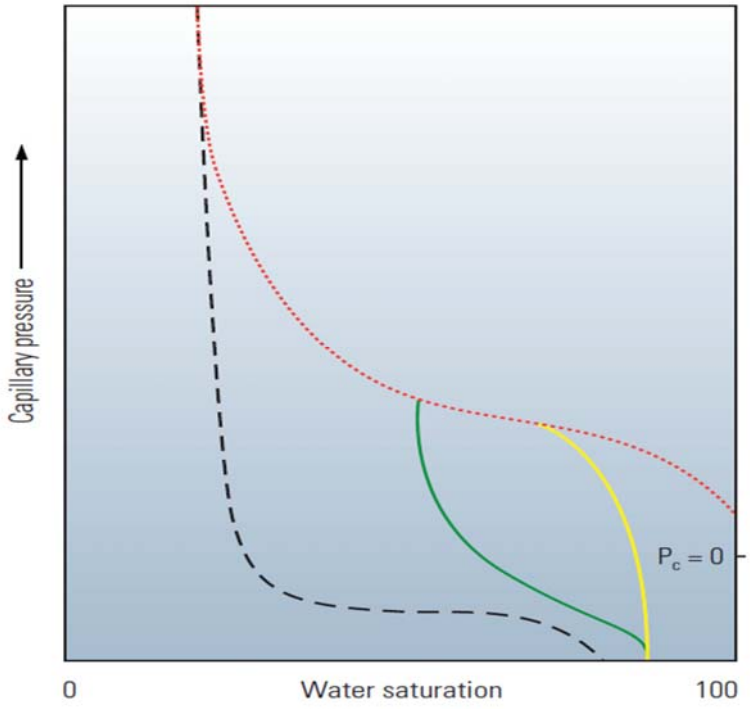
The hysteresis effect

- **Model used to simulate reservoir fluid flow when a non monotonous saturation variation exists during production (drainage, imbibition cycles)**
  - Important W/O transition zone or strong capillary effect in dynamic
  - Gas storage in aquifer reservoir
  - Gas injection after water sweeping, tertiary recovery process (WAG)
  - Variation of the WOC or GOC
  - Water injection in depleted reservoir having mobile free gas

Definition of the hysteresis effect

- In both water-wet and mixed-wet conditions, hysteresis in relative permeability and capillary pressure accompanies changes in saturation. This reflects the difference between water-advancing and water-receding contact angles, and the location of oil and water in the pore spaces.

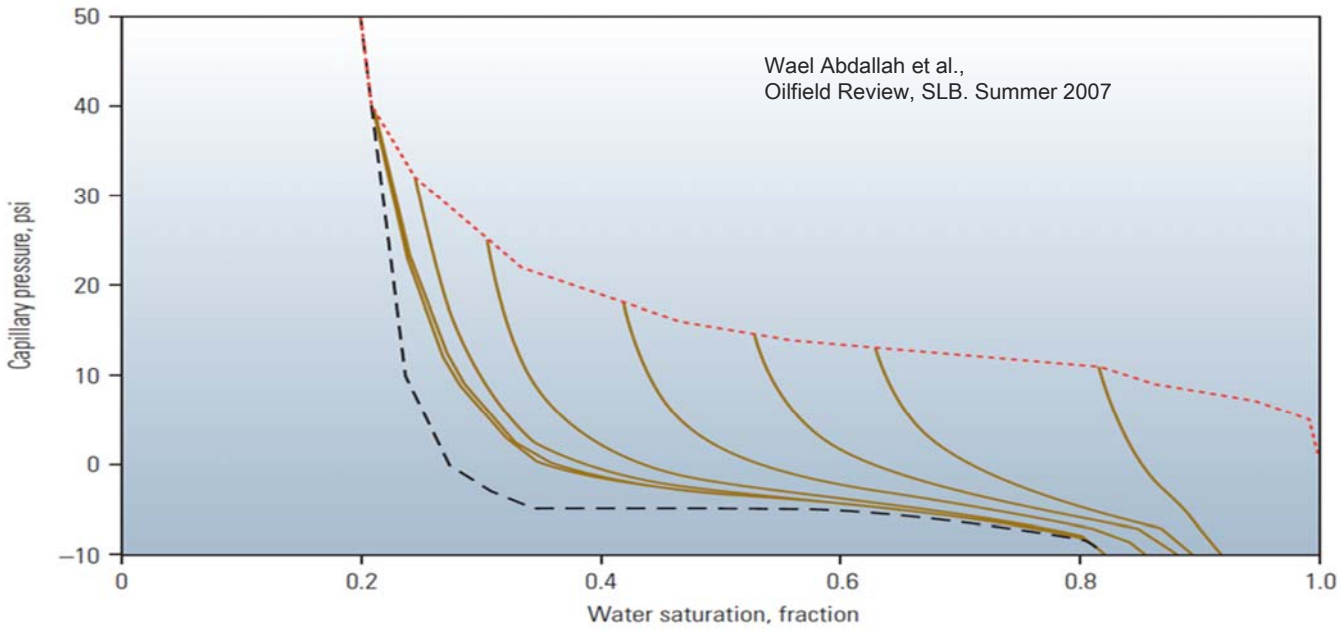
Definition of the hysteresis effect



Wael Abdallah et al.,
Oilfield Review, SLB. Summer 2007

- The primary drainage (red) and imbibition (black) curves bound the capillary pressure behavior. If the direction of saturation change is reversed at an intermediate saturation, Pc will follow an intermediate path (green). Another reversal will take it back to the drainage curve (yellow).
- This behavior could occur in the middle of a transition zone, or as a result of oil banking during a water flood.

Hysteresis modeling

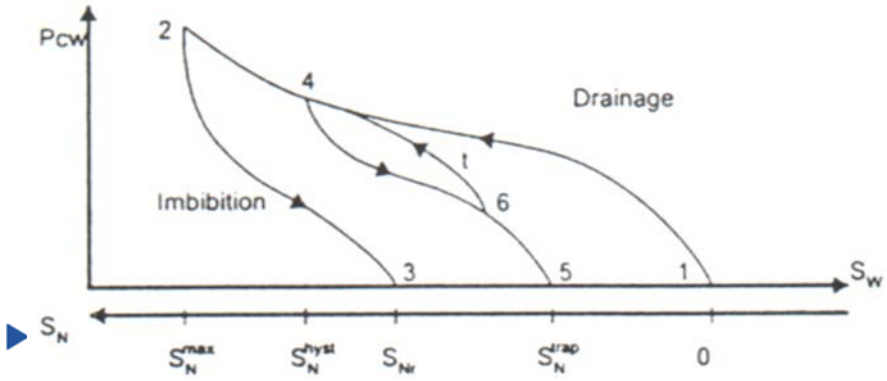


- **Hysteresis between the primary drainage (red) and imbibition (black) curves can be represented by a series of scanning curves (gold). Each scanning curve represents a different starting saturation point on the drainage or imbibition curve, which would correspond to different heights in the transition zone.**

Hysteresis modeling

- **The user provides the simulator with imbibition and drainage curves**
- **The simulator computes the scanning curves depending of the saturation history**
  - SN: non wetting fluid saturation (e.g.: So)
  - SNrmax: maximal residual non wetting fluid saturation (e.g.: Sorw)
  - SNmax : maximal non wetting saturation (e.g.: 1-Swi with WO)
  - SNrhyst: non wetting saturation when the direction of saturation change is reversed (e.g.: drainage to imbibition)
- **The scanning curves are always reversed**
- **Several available hysteresis models:**
  - Killough
  - Carlson
  - Jargon

Pc hysteresis modeling



- Should another reversal in the direction of saturation change occur while Pc is in a scanning state, a new scanning curve is generated that scans back to the point where the bounding curve was left originally.

- New interpolating function is used that depends on the new reversal point, the remembered reversal point, the present saturation and the regression parameter

- **SNr is computed by Land formula:**

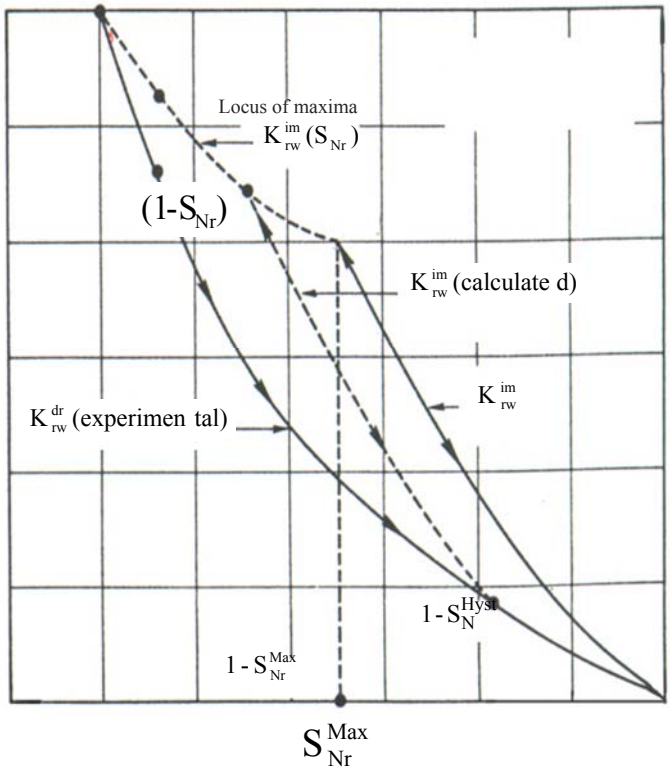
$$S_{Nr} = \frac{S_N^{hyst}}{1 + C.\,S_N^{hyst}} \qquad C = \frac{1}{S_{Nr}^{\max}} - \frac{1}{S_N^{\max}}$$

Pc curves: Recommendations for use in a simulator

- **Use the drainage Pc in static and dynamic**
  - Only if the transition zone is small so that the effect is negligible in dynamic (e.g. Pc imbibition is ≈ 0 or small layer thickness or weakly heterogeneous model)
  - Interest
    - the data is simpler
    - CPU time is lower
- **Use the hysteresis Pc in other cases**
  - input the imbibition Pc curves
  - if no measurement, estimate imbibition curves going from Pcmax to 0

kr hysteresis modeling (e.g. Killough)

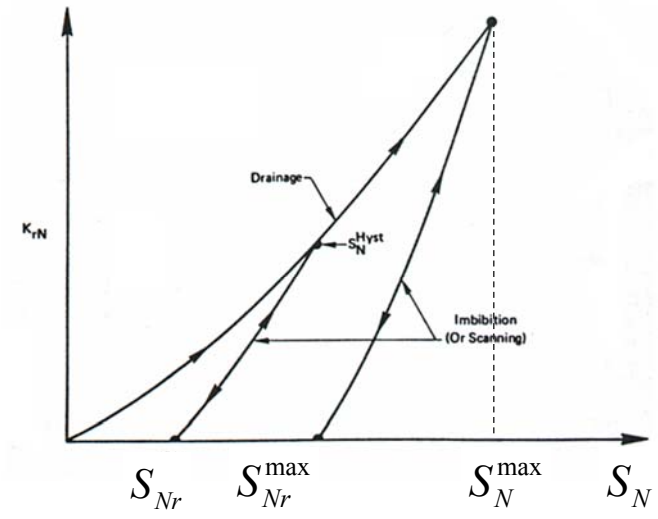
Wetting phase



- Wetting phase is treated differently
- Computed Imbibition Relative Permeability curves are reversible
- Killough model predicts the maximum wetting relative permeability by interpolating between the “known” imbibition relative permeability at the maximum residual non wetting saturation and the value of the drainage wetting relative permeability at the maximum wetting-phase saturation (trapped non wetting saturation equal to zero or Snc)

kr hysteresis modeling (e.g. Killough)

Non–wetting phase



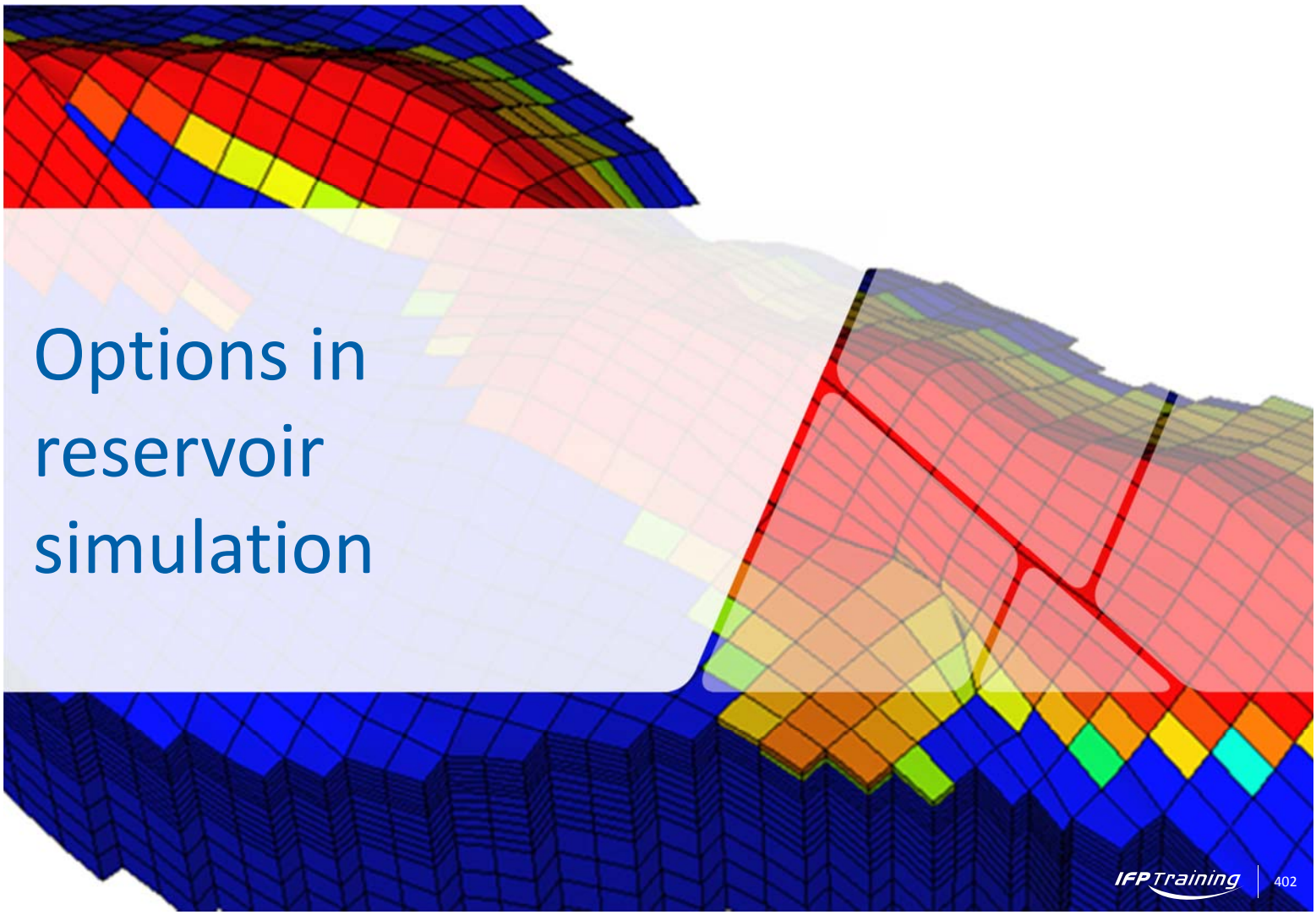
$$S_{Nr} = \frac{S_N^{hyst}}{1 + C.\ S_N^{hyst}}$$

$$C = \frac{1}{S_{Nr}^{max}} - \frac{1}{S_N^{max}}$$

- Parametric interpolation for the scanning imbibition curves

Hysteresis modeling: remarks

- Carlson Pc model may result in errors when computing the recovery by spontaneous imbibition in fractured reservoir.
- In Eclipse, capillary pressure hysteresis is always applied using the Killough method
- Carlson kr model: no hysteresis on the wetting phase, only on the non wetting phase.
- Carlson's method produces a scanning curve that is parallel to the imbibition curve. When this method is chosen, it is important to ensure that the imbibition curve is always steeper than the drainage curve at the same kr value. If this is not the case, the scanning curve could cross to the right of the drainage curve, which may produce an unphysical situation (SNr< 0).



Options in reservoir simulation

Relative permeability

Endscale option

Objectives

- **Modify relative permeabilty tables in an easy way, kr tables are normalized and remain always the same, only the end-points are changed and kr curves are then recalculated.**

- **It's a useful option in History Match simulations.**

Relative permeability keywords

KRO: Maximum oil relative permeability

KRORW: Oil relative permeability at critical water saturation Swcr

KRWR: Water relative permeability at residual oil saturation (1-Sowcr)

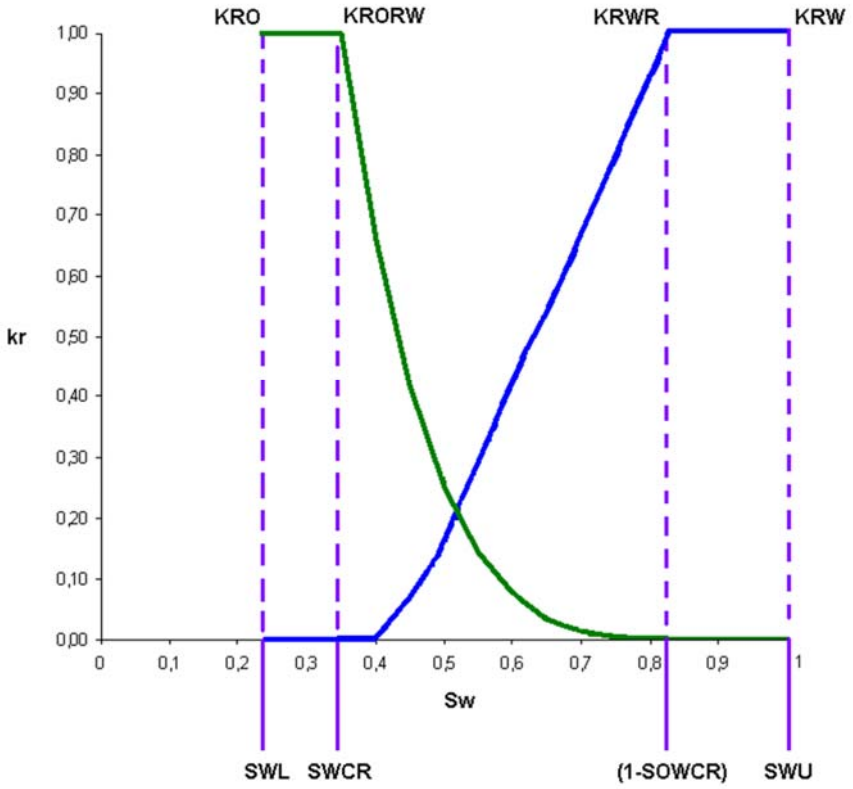
KRW: Maximum water relative permeability

SWL: Connate water saturation

SWCR: Critical water saturation

SOWCR: Residual oil saturation

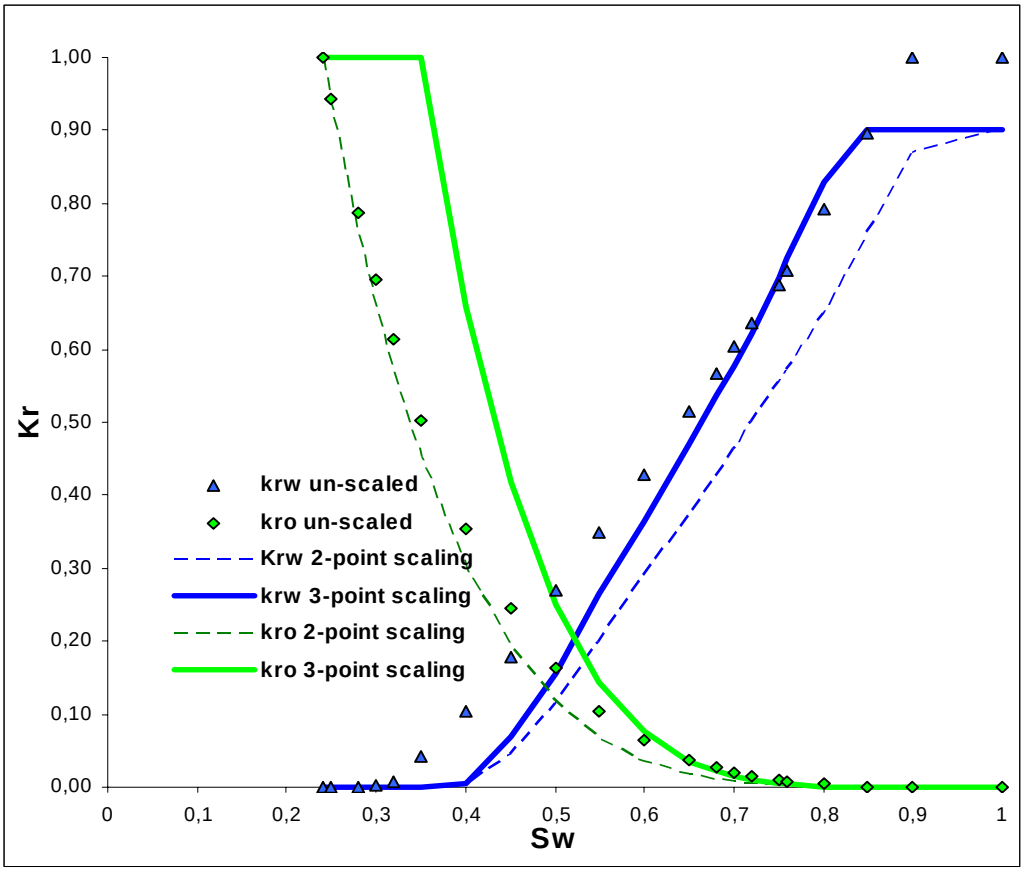
SWU: Maximum water saturation



Relative permeability Example 1

SWL= 0.24

SWCR= 0.35

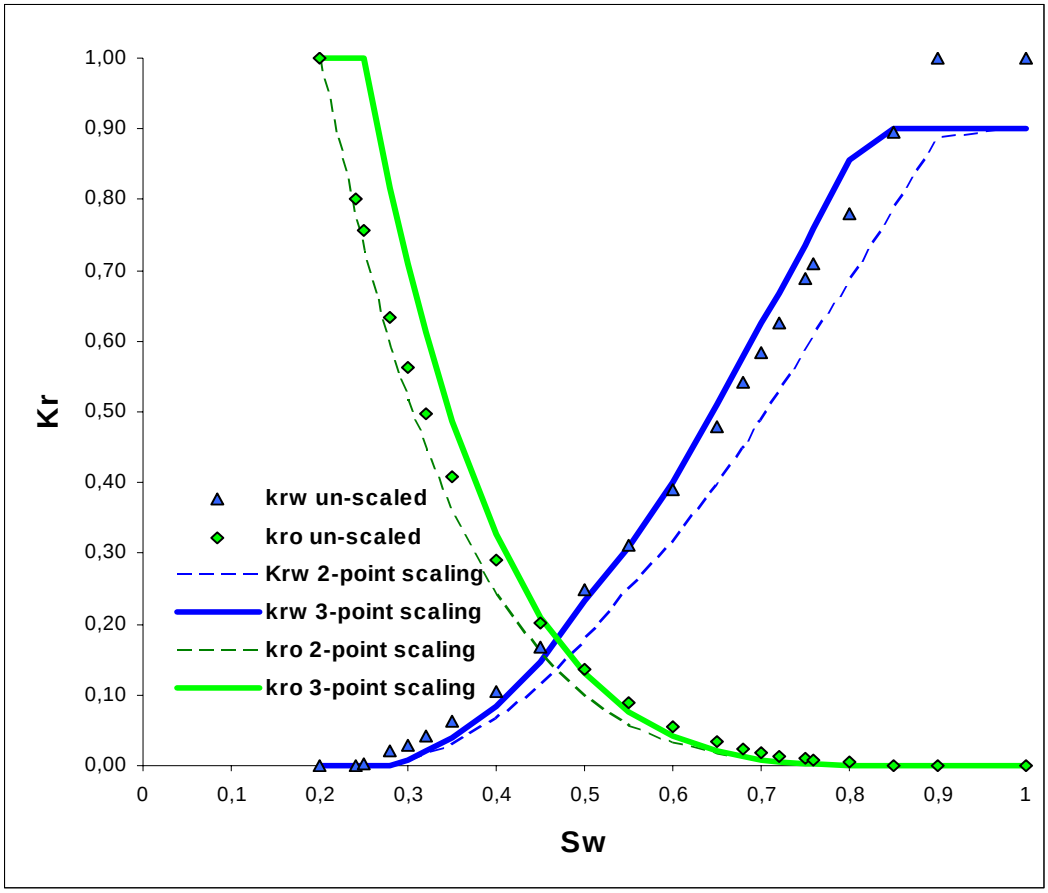


Relative permeability

Example 2

SWL= 0.20

SWCR= 0.25



Key points to keep in mind

Relative permeability

- **Relative permeabilities**
  - When two (or more) fluids flow simultaneously in a rock / in a reservoir, this results in permeability reduction for each fluid permeabilities
  - Depends on saturation
- **Relative permeability**
  - The ratio of effective permeability to absolute permeability
  - Absolute permeability is the permeability of the rock when totally saturated with one fluid
  - Effective permeability is the permeability of the rock when partially saturated with one fluid
- **Relative permeability**
  - Allows to generalize Darcy's law to multiphasic flows in the reservoir
  - Is defined by a curve as a function of saturation, typically $\mathbf{k_{ro}(S_w)}$ and $\mathbf{k_{rw}(S_w)}$
- **Relative permeability curves**
  - Depend on wettability
  - Rule flow of fluids (water and hydrocarbons) in the reservoir and have a strong influence on the Recovery Factor

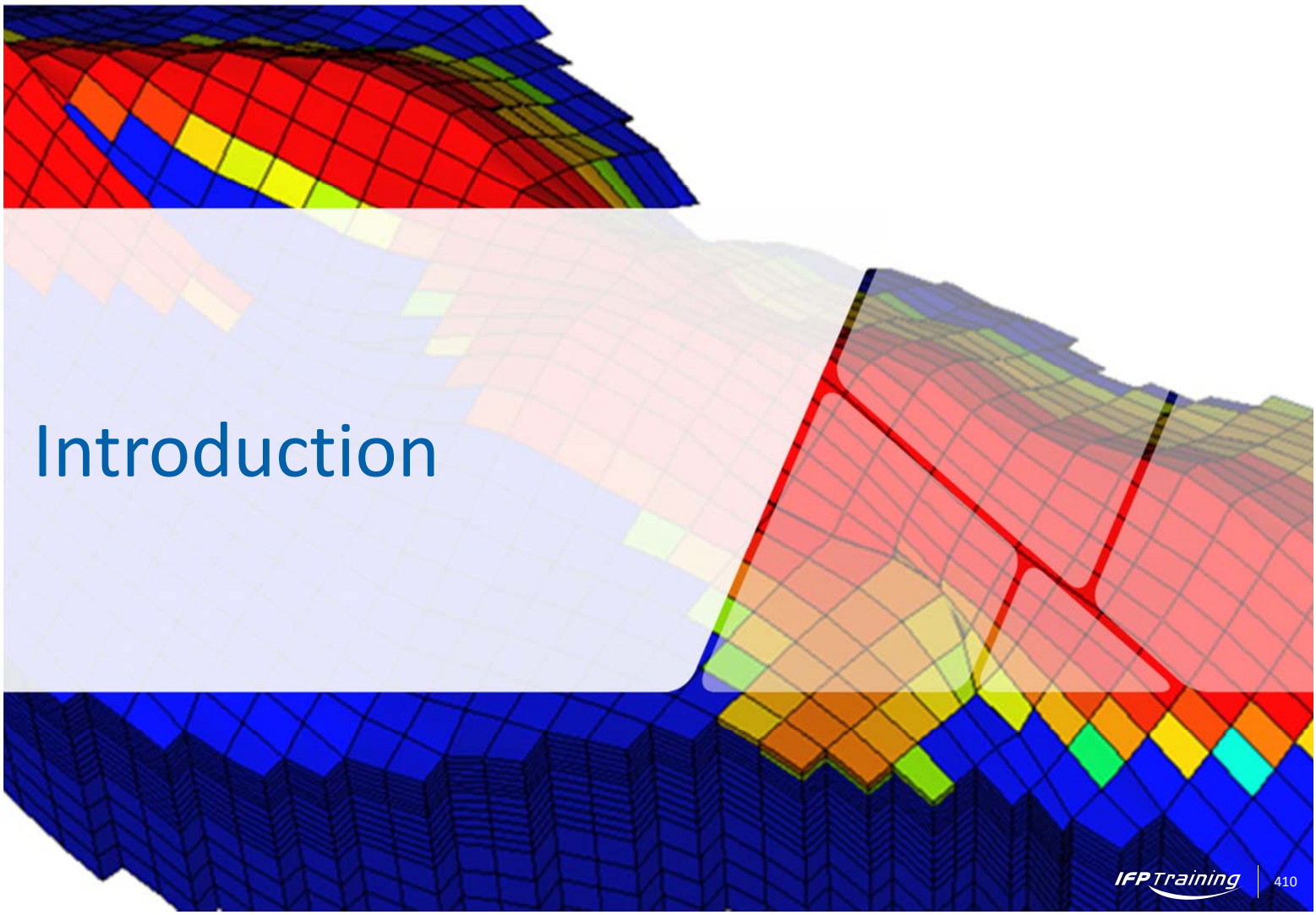


Dynamic reservoir simulation
Data review: Well representation

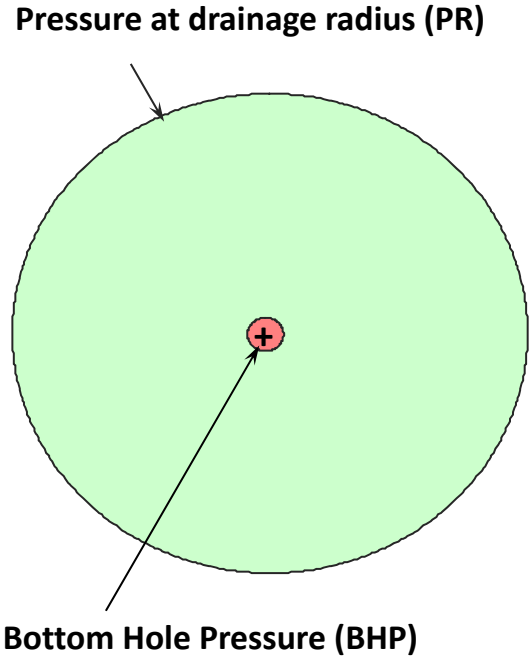
IFP Training

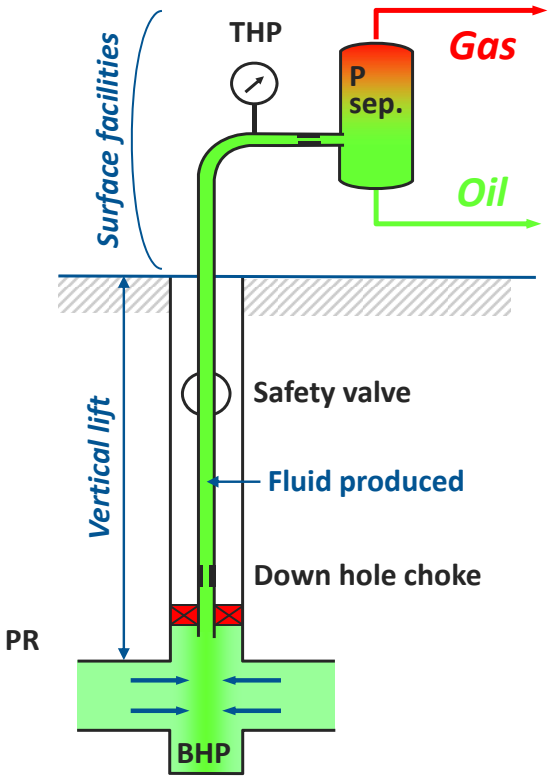
Sommaire

- Introduction 410
- Wells representation 416
- Numerical PI 424
- Well performance 434
- Well constraints 446
- Exercise
  Wells' controls 456

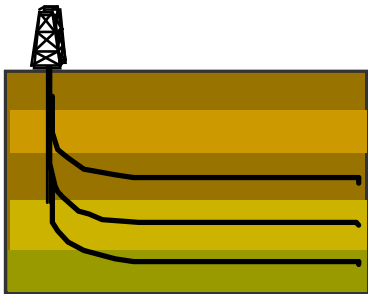


Wells description: basic data

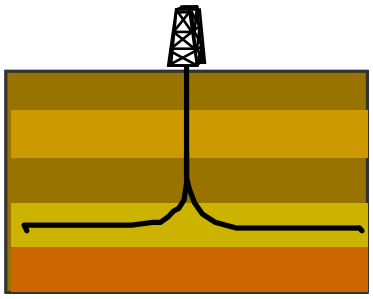




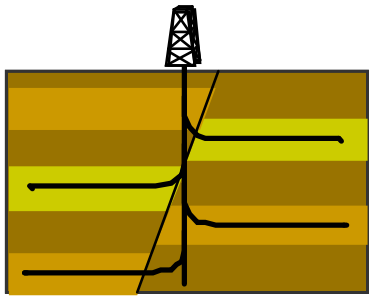
Different complex wells



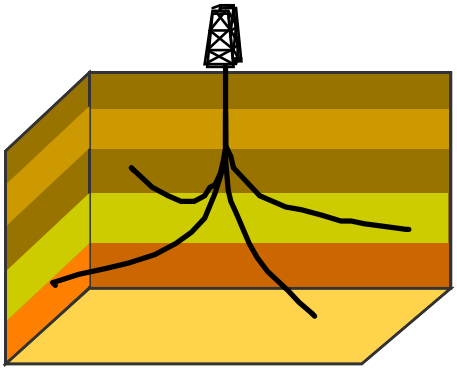
Stacked multibranch well



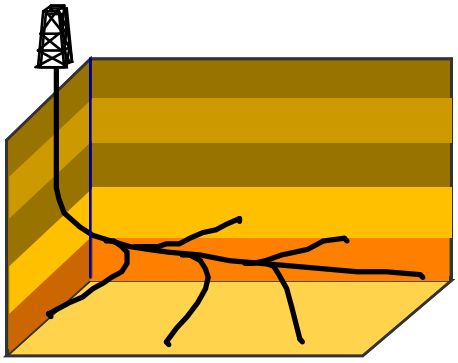
Dual opposing laterals



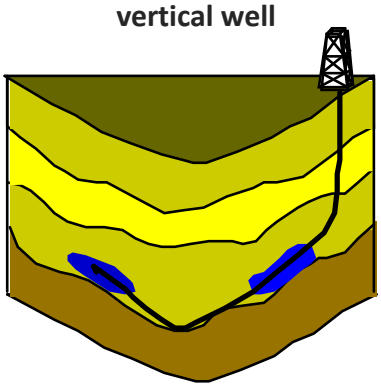
Re-entry laterals from a vertical well



Cluster well



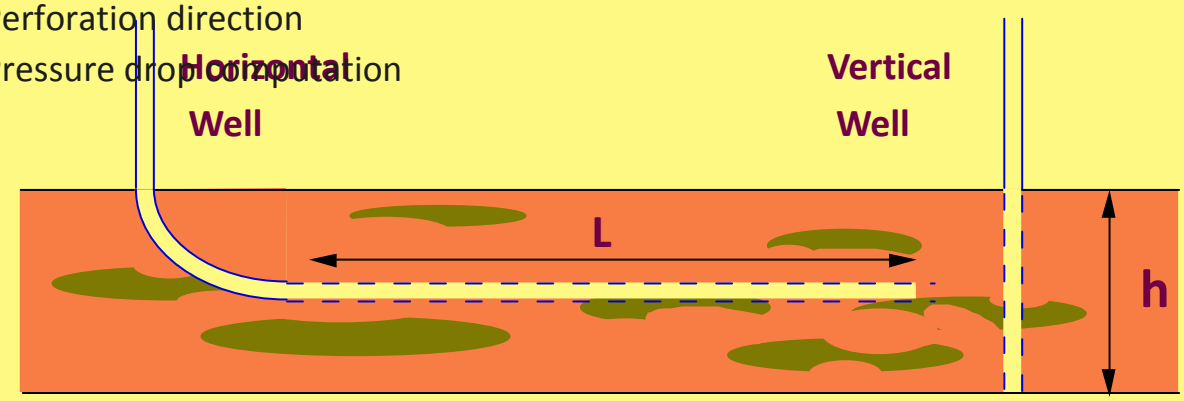
Multidrain or multilateral well



3D Well

Vertical vs. horizontal well

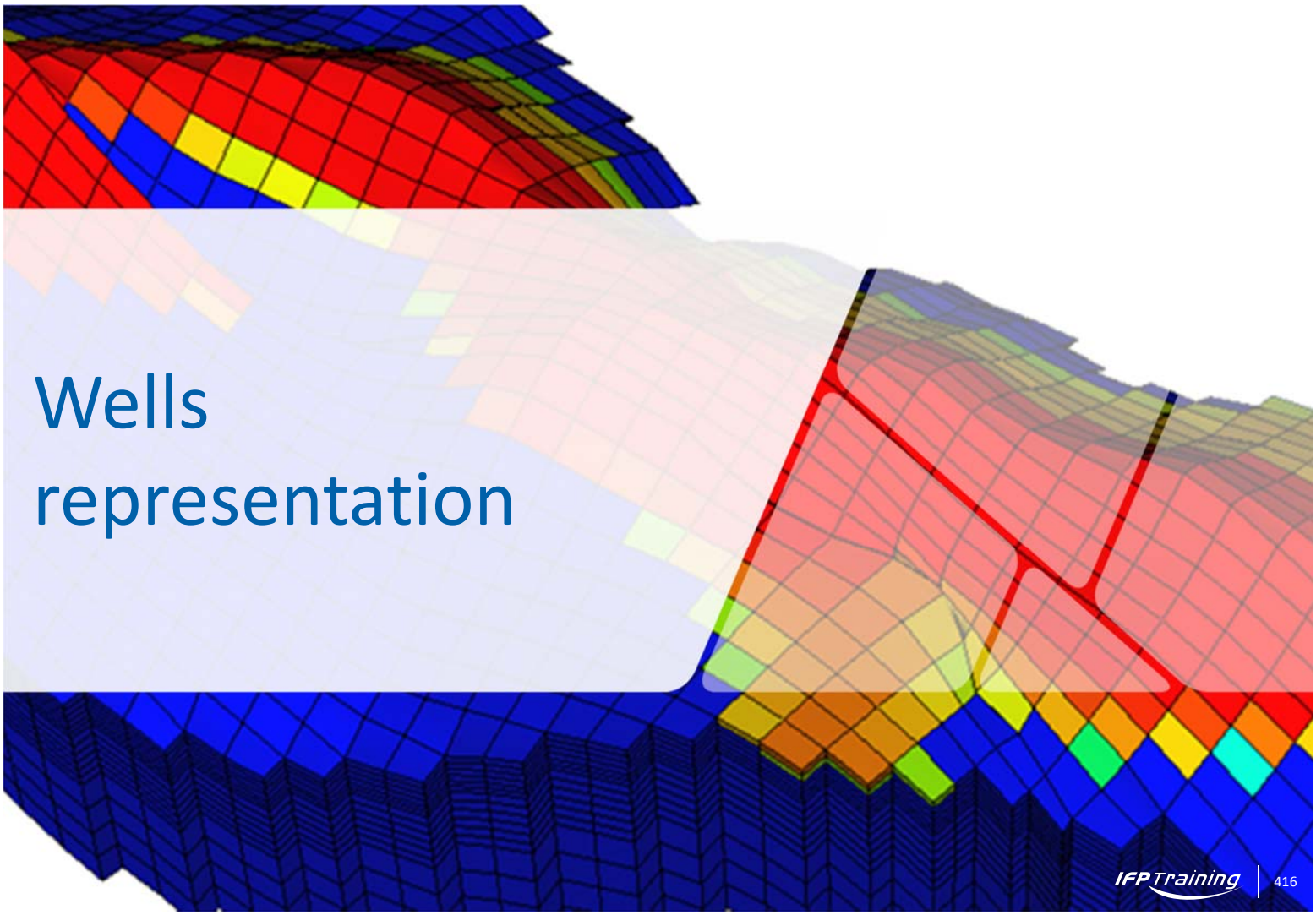
- **For a simulator the only differences are:**
  - Perforation direction
  - Pressure drop computation



L / h > 100

Wells representation

- **The flow from the formation to the bottom of the well is governed by what is known as the INFLOW - OUTFLOW PERFOMANCE relationship of the well.**
- **Wells Representation – Geometry**
  - Wells radii are very small compared to well cells (~1/1000)
  - Wells are considered as source points in the well cells
- **Inflow Performance**
  - Geometry of perforated intervals
  - Inflow performance relationship per perforated interval
- **Outflow Performance**
  - Pressure drop through tubing and surface installations
- **Well control**
  - Production schedule (oil rate, gas rate, reservoir void age…)
  - Minimum Bottom Hole flowing pressure
  - Minimum Well Head flowing pressure



Wells representation

Well's representation

The problem in reservoir simulation

- **Problems:**
  - The well is too small to be represented explicitly, typically rw = 0.001 Dx
  - The well borehole cannot be represented explicitly within the reservoir grid
  - Size and geometry of blocks are not well suited to model physics of flow around the wells:
    - radial fluxes
    - large gradients of pressure and saturation
  - The high pressure gradient near the well is not usually resolved
    - a special model is required

The problem in reservoir simulation

- **"Solution":**
  - Injection and production wells are represented as source or sink terms
    - Continuity equation:

$$\nabla(\rho \cdot \vec{V}) + \Phi = \frac{\partial \rho}{\partial t}$$

    - Well equation:

$$\Phi = Q_{well} = f(Pw, Pb)$$

      - where:
      - Pw is the well bore pressure
      - Pb is the grid block pressure

Wellbore vs perforated grid block

- **A well is represented in block 'i' through the production/injection at qp**

$$\left(\frac{\Delta m}{\Delta t}\right)_{block\ i} = \sum_{phase\ p} [(in\ 'i') - (out\ 'i') - q_{p,i}]$$

- **qp must be related to:**
  - block pressure and saturation: Pb and Sb
  - bottom hole pressure (flowing): Pw

- **The pressure – rate relationship determines the boundary conditions:**
  - History matching: Q imposed → Pw
  - Forecasting: Pw imposed → Q

Well's representation

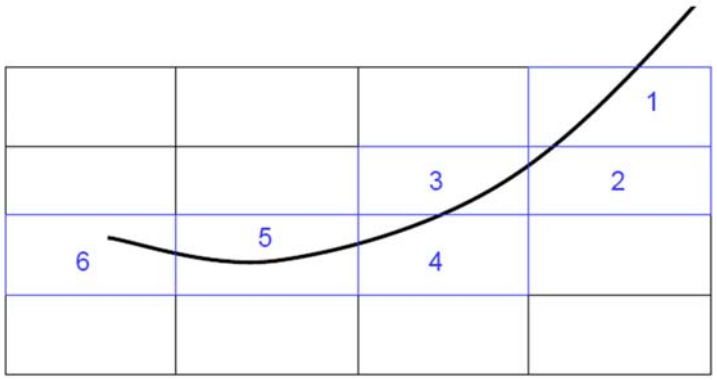
Well bore vs perforated grid block

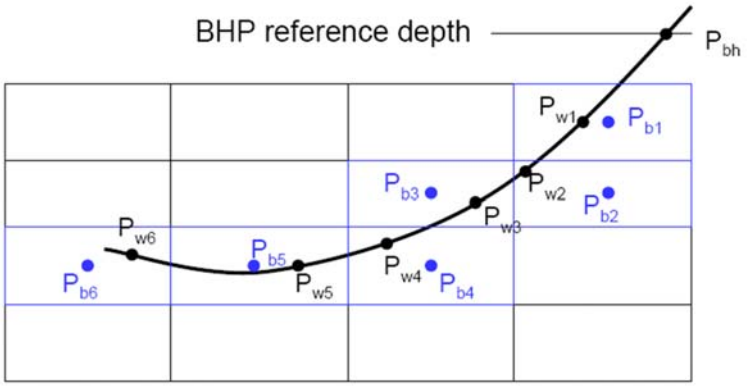
Important:

- Where the well is perforated
- Grid block intersected by the well trajectory
- Connections

Calcul of simulator:

- Pressure for each grid block, Pb
- Well bore pressure for each connection, Pw
- Well's BHP at a reference depth, Pbh





Well's representation

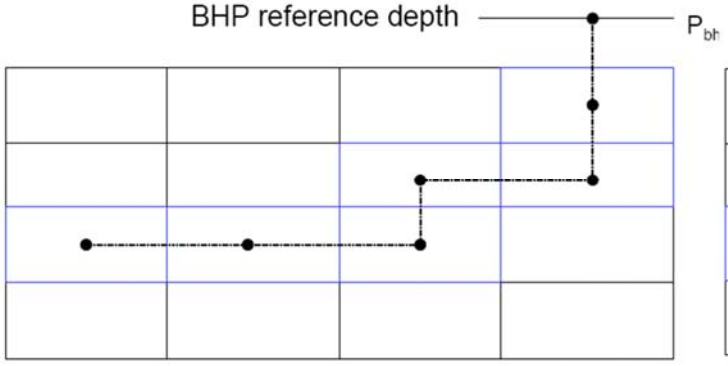
Well bore vs perforated grid block

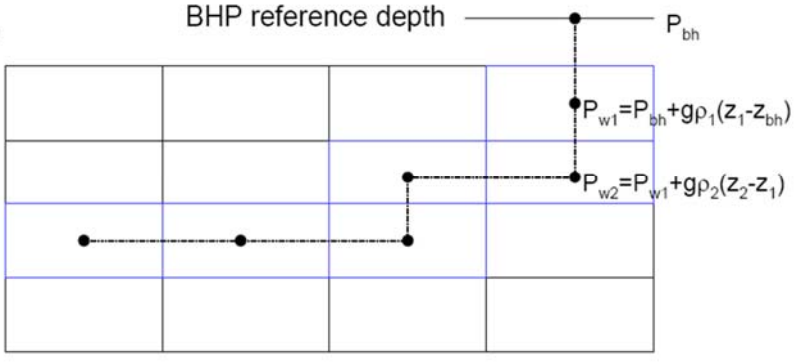
Simulator well model:

- The well is defined by a list of connections
- There is not notion of trajectory
- Completions may be ordered by depth

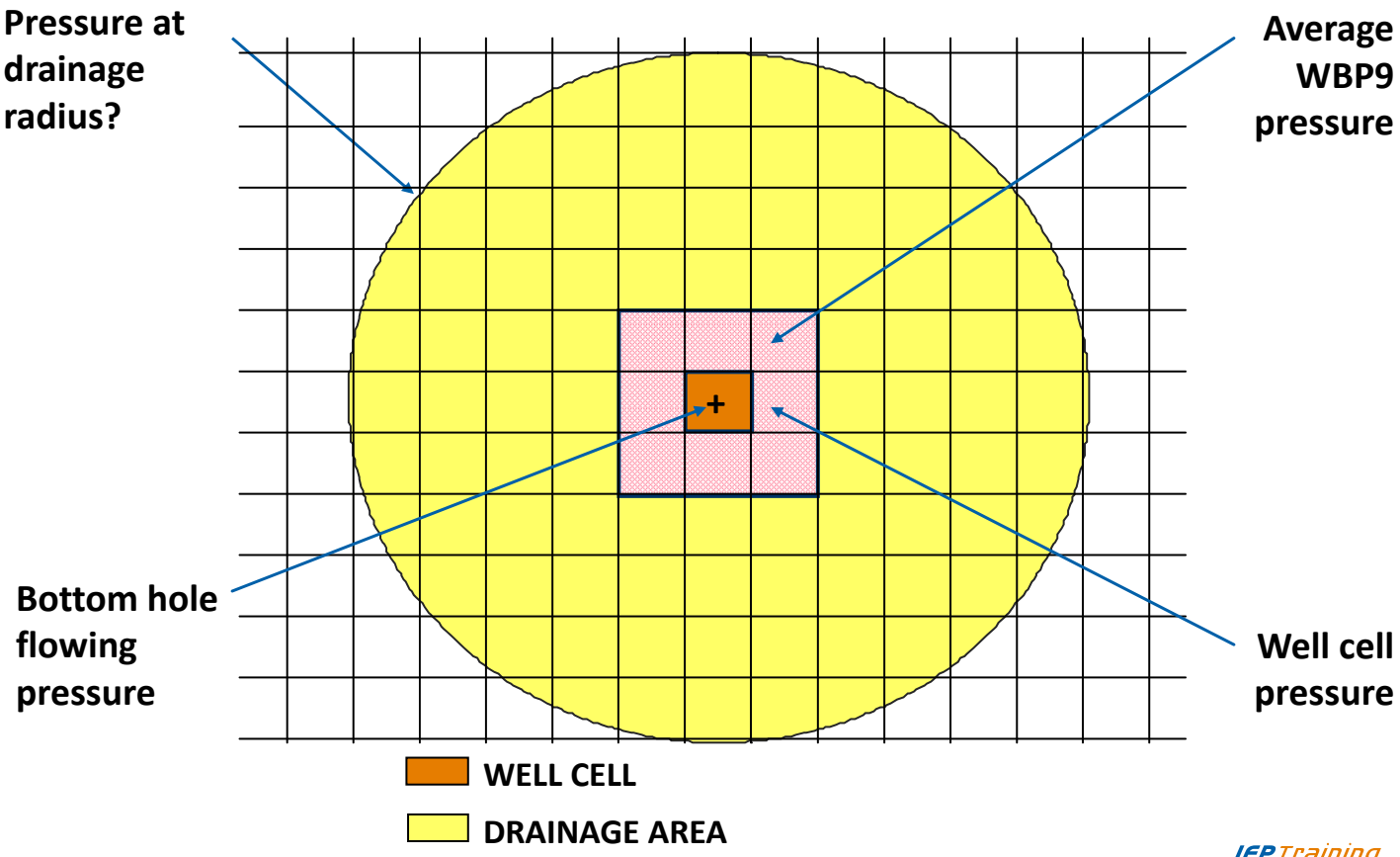
Calcul of simulator:

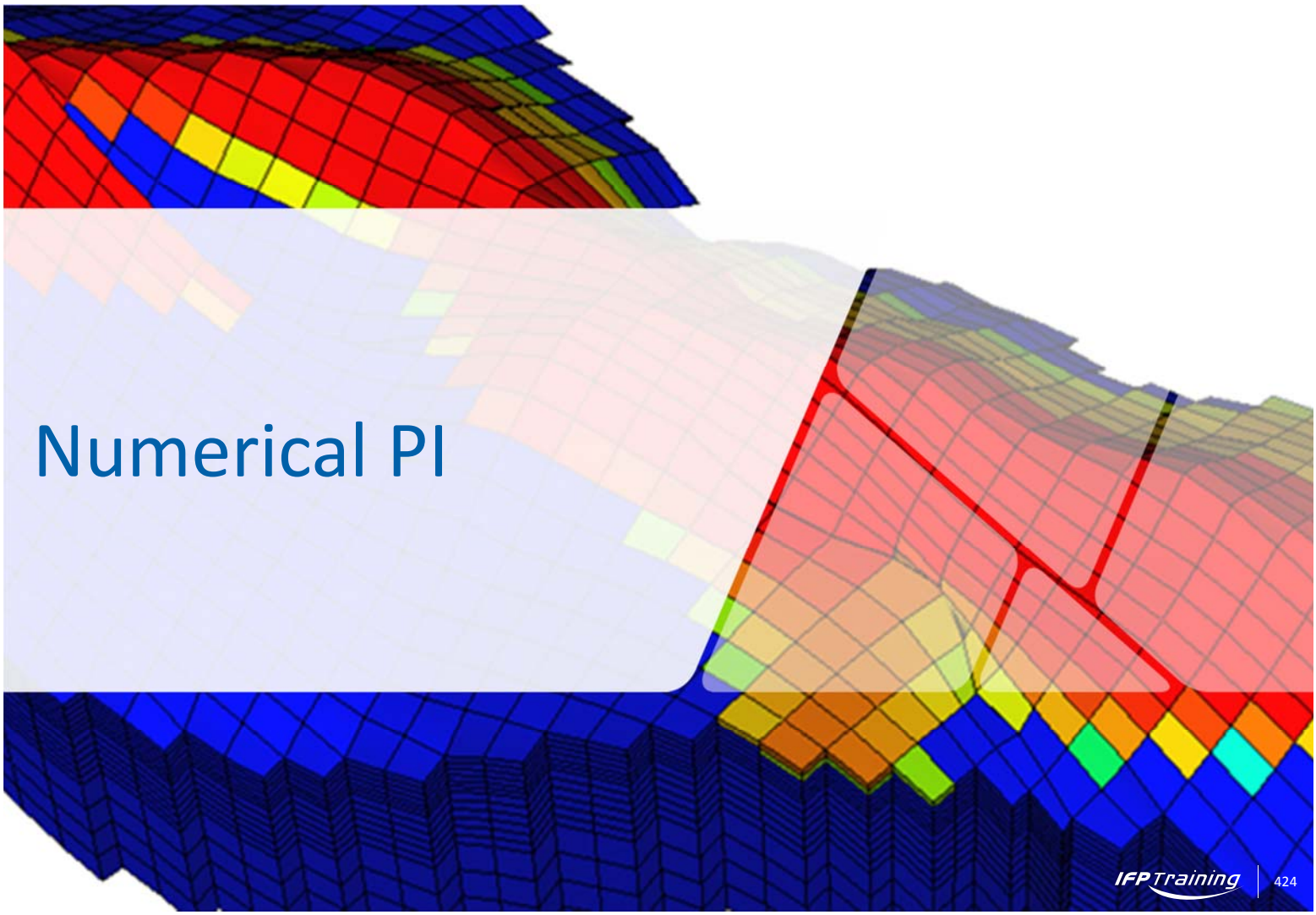
- Gravity effect only
- No friction or acceleration losses
- Average density calculated for each segment





Wells representation: wells' Geometry





Numerical PI

Connection factor

Definition

- **The production or injection rate of phase p for well connection k is:**

$$q_{p,k} = CF_{well,k} \frac{kr_p(S_{p,b,k})}{\mu_{p,b}} (P_{b,k} - P_{well,k})$$

- **CF well is the Connection Factor, the well connection transmissivity or the numerical productivity index (numerical PI).**

- **NOTE:**
  - Pressures in the equation must be at the same reference depth
  - for a gas well, pseudo-pressure and non-Darcy flow may be considered, resulting in a different equation

Connection factor (numerical PI)

Numerical pressure–rate relationship

- For the phase p, the rate between two grid blocks 'i' and 'i+1':

$$Q_{pi,i+1} = T_{i,i+1} \frac{kr_{pi}(S_{pi})}{\mu_{pi}} (P_i - P_{i+1})$$

- qp between the well and the block (b):

$$q_{pwell} = CF_{well} \frac{kr_p(S_{pb})}{\mu_{pb}} (P_b - P_{well})$$

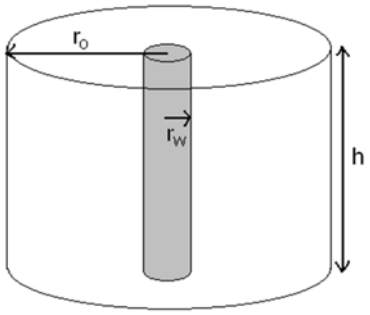
- Pb and Sb are average values at the scale of the block, the pressure–rate relationship should take into account the physical gradients localised around the well and within the block volume: role of CF and kr(Sb)

Connection factor (numerical PI)

Analytical pressure–rate relationship

- Assuming radial flow, for steady–state and single phase:

$$q_p = \left(\frac{2\pi \cdot K \cdot h}{\mu_p} \right) \frac{(P(r_o) - P_w)}{\ln(r_o / r_w)}$$

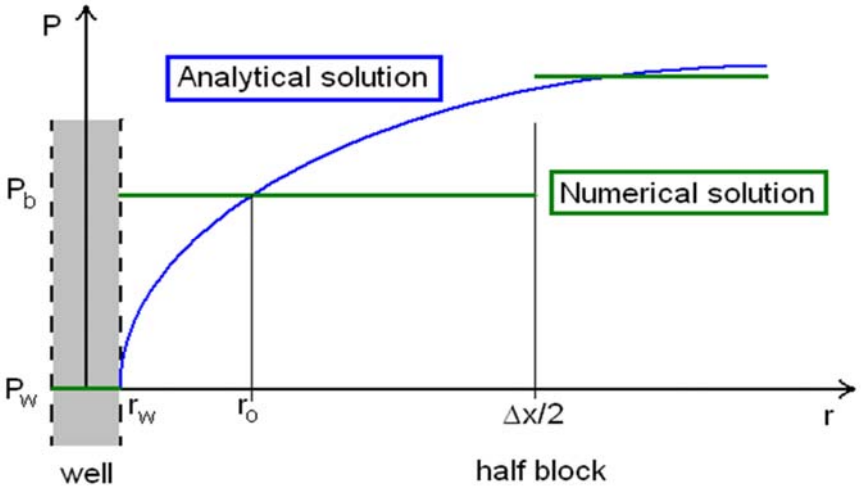


- If ro is such that P(ro) = Pb, the we derive the Connection Factor:

$$CF_{well} = \frac{2\pi \cdot K \cdot h}{\ln(r_o / r_w) + S}$$

Connection factor (numerical PI)

Analytical vs Numerical solution



$$CF_{well} = \frac{2\pi \cdot K \cdot h}{\ln(r_o / r_w) + S}$$

$$CF_{well} = \frac{\mu_{pb}}{kr_p(S_{pb})} \cdot \frac{q_{pwell}}{(P_b - P_w)}$$

Natural PI vs numerical PI

Numerical PI (CF):

- Specific to the grid block containing the well
- Units: m^3.cP/(d.bar)
- Independent of the phase produced
- Constant in time

Natural PI:

- Related to the whole drainage area
- Units: m^3/(d.bar)
- Depends on the phase produced
- Varies with time

$$CF_{well} = \frac{2\pi \cdot Kh}{\ln(r_o / r_w) + S}$$

$$PI = \frac{Q_{surface}}{(P - BHP)}$$

$$PI_{num} = \frac{2\,\pi\,k\,h}{B\,\mu\,(\mathrm{Ln}\ r_b/r_w + S + Cte)}$$

$$PI_{nat} = \frac{2\,\pi\,k\,h}{B\,\mu\,(\mathrm{Ln}\ r_e/r_w + S + Cte)}$$

$$PI_{num} = PI_{nat} \times \frac{\mathrm{Ln}\ r_e/r_w + S + Cte}{\mathrm{Ln}\ r_b/r_w + S + Cte}$$

Connection factor (numerical PI)

Peaceman's formula for ro

- **For a vertical well in the centre of a square grid block, Pb = P(ro) if:**

$$r_o = 0.198 \cdot \Delta x$$

- **Assumptions:**
  - Vertical well
  - 2D
  - Pseudo–permanent, radial flow
  - Regular grid
  - Isotropic, homogeneous, non–dipping reservoir
  - Well far from other wells and reservoir boundaries
  - Well axis and axis aligned

- **If Dx = Dy, even considering anisotropy ratio Ky/Kx:** $r_o = 0.198 \cdot \Delta x$

Connection factor (numerical PI)

Peaceman's formula for ro

- **Isotropic Reservoir – Square grid**

  $r_{w,b} = 0{,}20\ \Delta x$

- **Isotropic Reservoir – Rectangular grid**

  $r_{w,b} = 0.14\sqrt{\Delta x^2 + \Delta y^2}$

- **Anisotropic Reservoir – Rectangular grid**

$$r_{w,b} = 0.28\frac{\sqrt{(k_y/k_x)^{1/2}\Delta x^2 + (k_x/k_y)^{1/2}\Delta y^2}}{(k_y/k_x)^{1/4} + (k_x/k_y)^{1/4}}$$

Numerical PI (CF)

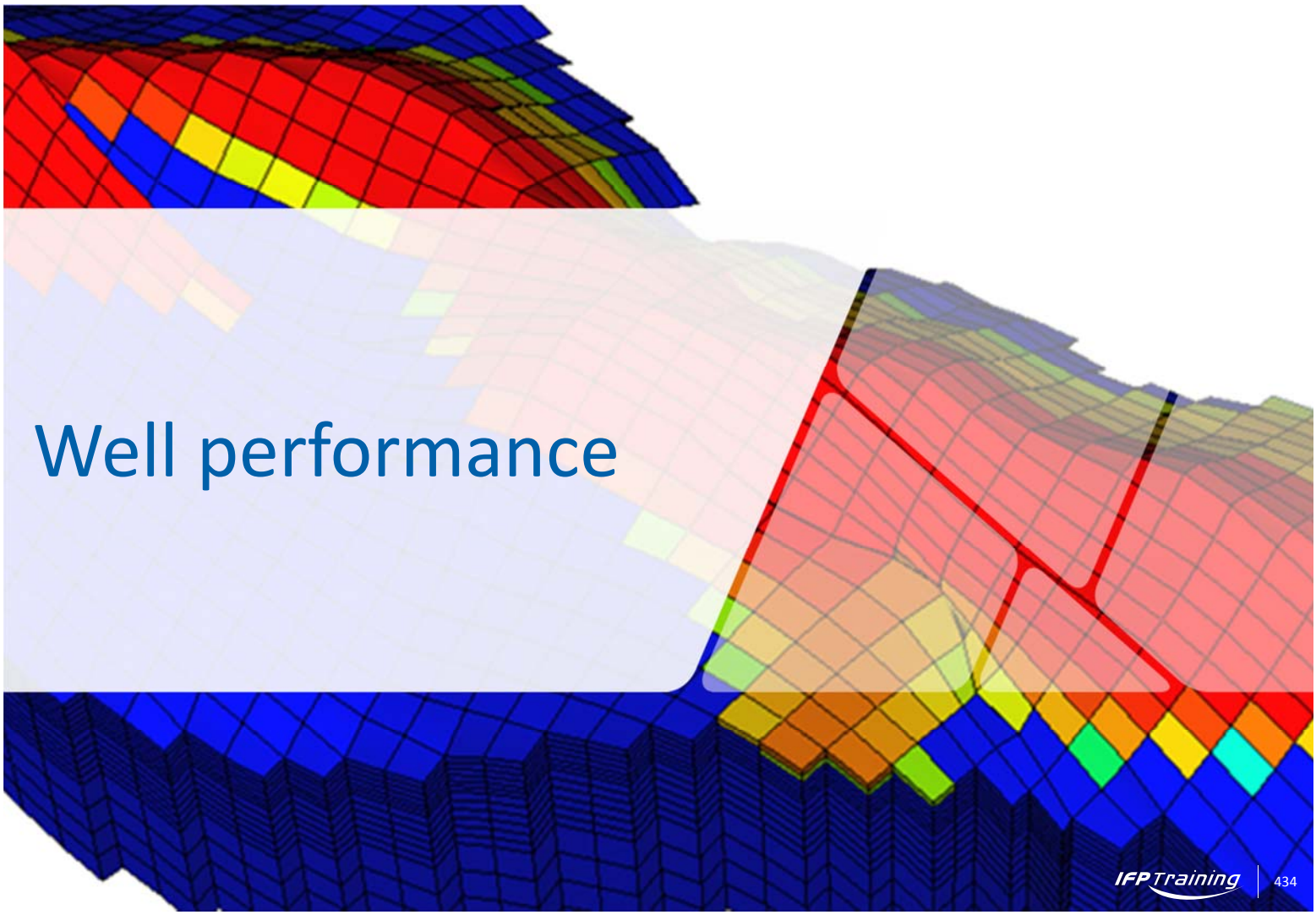
Importance

- **In History Match: calculation of ro in order to use Pbottom observations**
- **From History Match to Forecast:**
  - CF calibration by layers
  - Remember to update CF if grid cell permeability is changed (in HM)
- **In forecast:**
  - use CF computed by the simulator from rw, S, block data
  - compute CF with SCHEDULE
  - use available reservoir measures and adjust field PI
  - USE OF TOO HIGH VALUES MAY CAUSE NUMERICAL PROBLEMS!!!

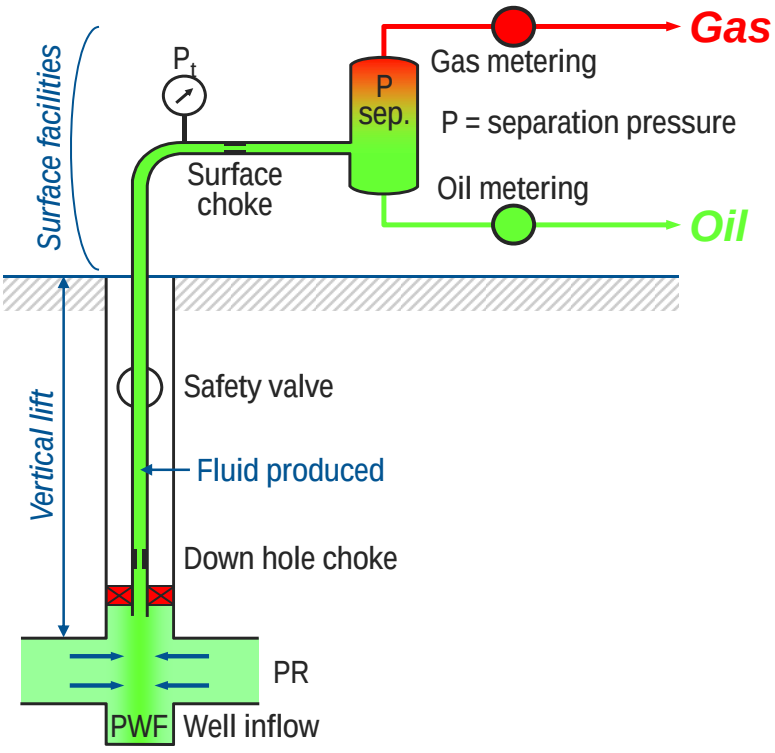
Components of skin (remind)

- **The global skin factor represents various phenomena:**
  - mechanical skin, Sm: local modification of permeability and effect of flow through the perforations.
  - geometric skin, Sg = Sd + Spp: effects of well geometry (deviation and partial perforation).
  - turbulence effect or quadratic skin, Sq: deviation from Darcy's law, representative of the turbulence effect. It mainly concerns gas wells but can be considered in the case of oil wells flowing at high velocity.

$$S = S_{pp} + \frac{h_t}{h_p}\left(S_m + S_g + S_q\right)$$

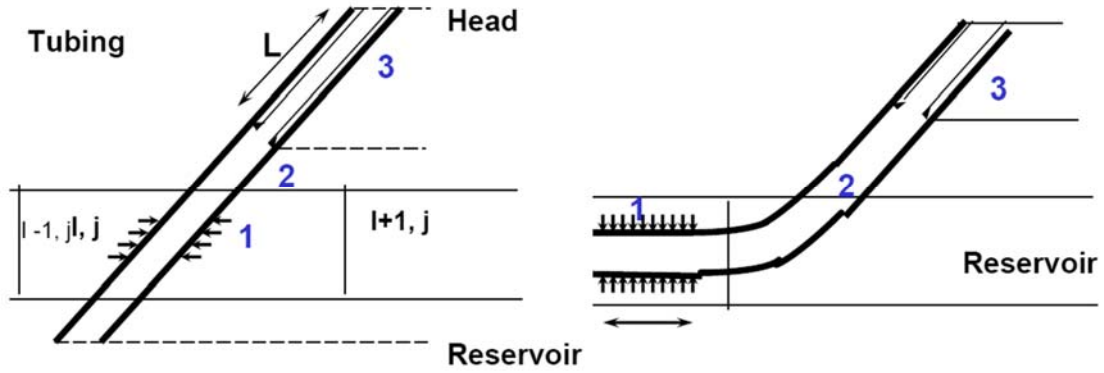


Bottom – surface relations



Inflow & outflow calculations

- **The total pressure drop has several components:**
  - Pressure drop between the reservoir and bottom hole: "inflow" (1)
  - Well bore pressure head between connection and datum of VFP table (2)
  - Head losses in tubing: "outflow" (3)



Deviated well **Horizontal well**

Inflow & outflow calculations

- **Inflow performance relationship (IPR): section 1**

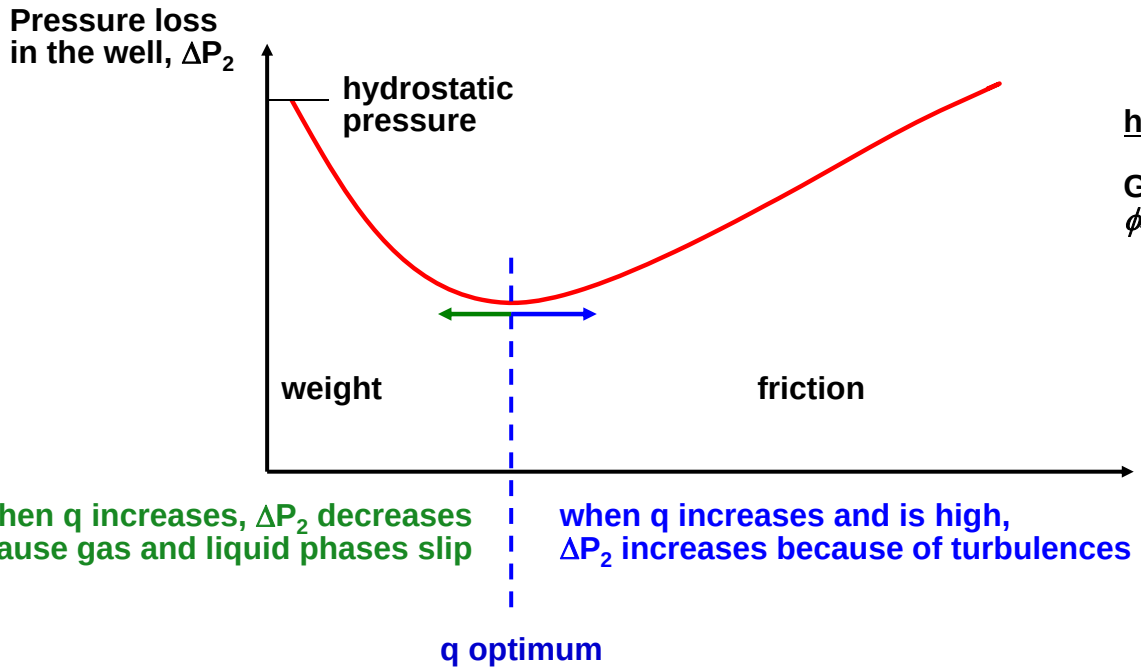
$$Q = CF \cdot \frac{kr}{\mu} \cdot (P_r - P_{wf})$$

- **Wellbore pressure head: section 2**
  - Vertical well: hydrostatic head rgDz between the well's datum "connection i" and the VFP table datum depth
  - horizontal well : hydrostatic head rgDz + friction

- **Pressure drop in tubing: section 3**
  - use of Vertical Flow Performance (VFP) tables provided in the data set
  - BHP = f (Q, THP, WCT, GOR, Qlift)

- **It is important to define accurately VFP tables when inflow drawdown is low**

Outflow performance, VLP



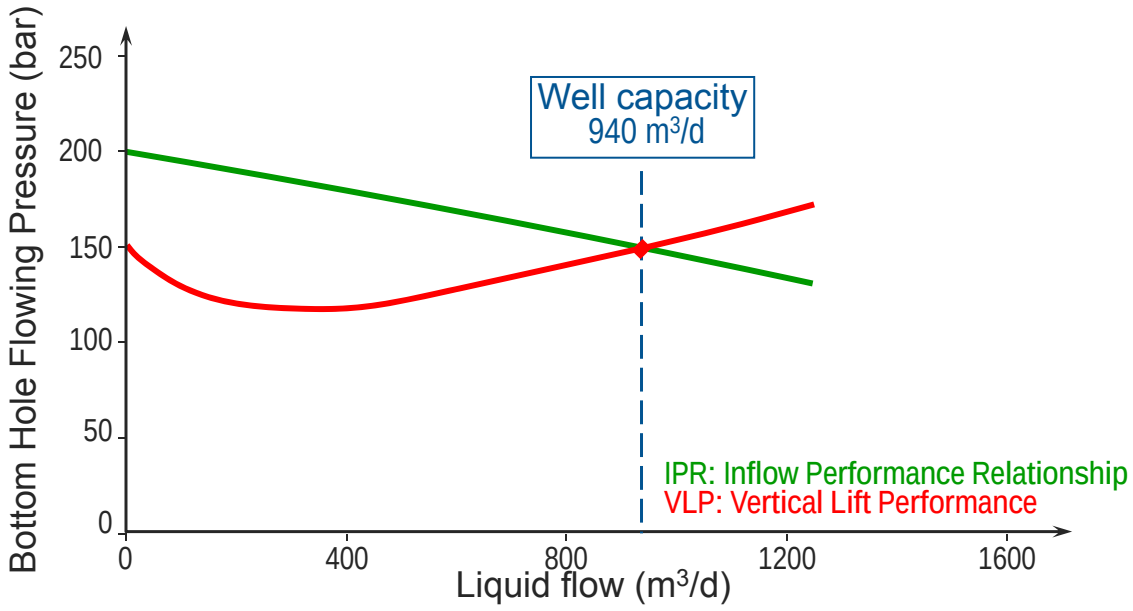
hypothesis:

GOR = ctt

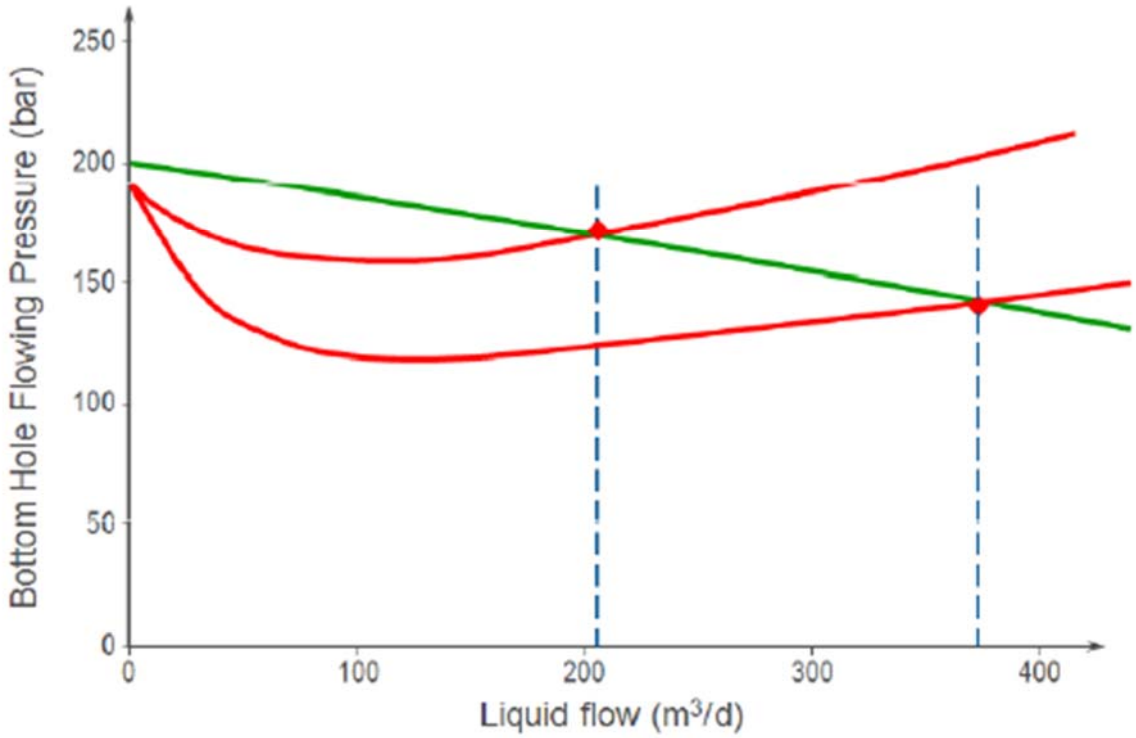
ϕ_{tubing} = ctt

Inflow & outflow

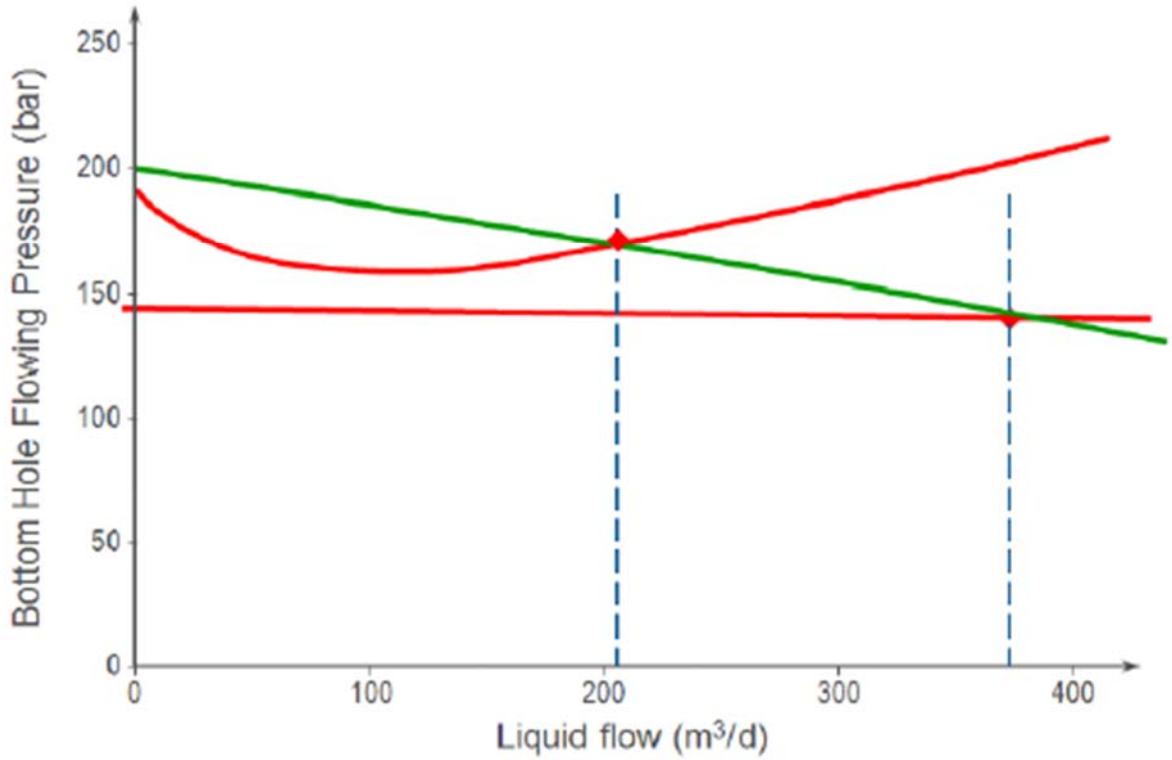
Well deliverability



Wells representation well control (gas lift)

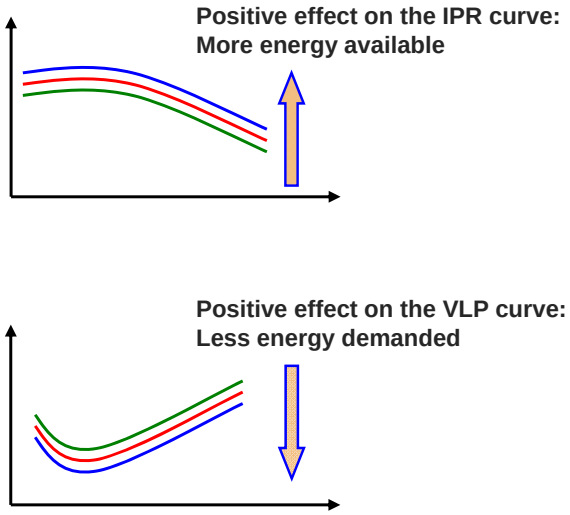


Wells activation – Bottom hole pumping



Inflow – outflow performance

parameter	IPR	VLP
Pres ↑	+	no effect
Pup ↑	no effect	-
WCT ↑	+	-
GOR ↑	-	+
ϕ_{tubing} ↑	no effect	+
S ↑	-	no effect
k_{ro} ↑	+	no effect



there is an optimum value for GOR: a compromise between column weight and turbulence!!!

Outflow calculations

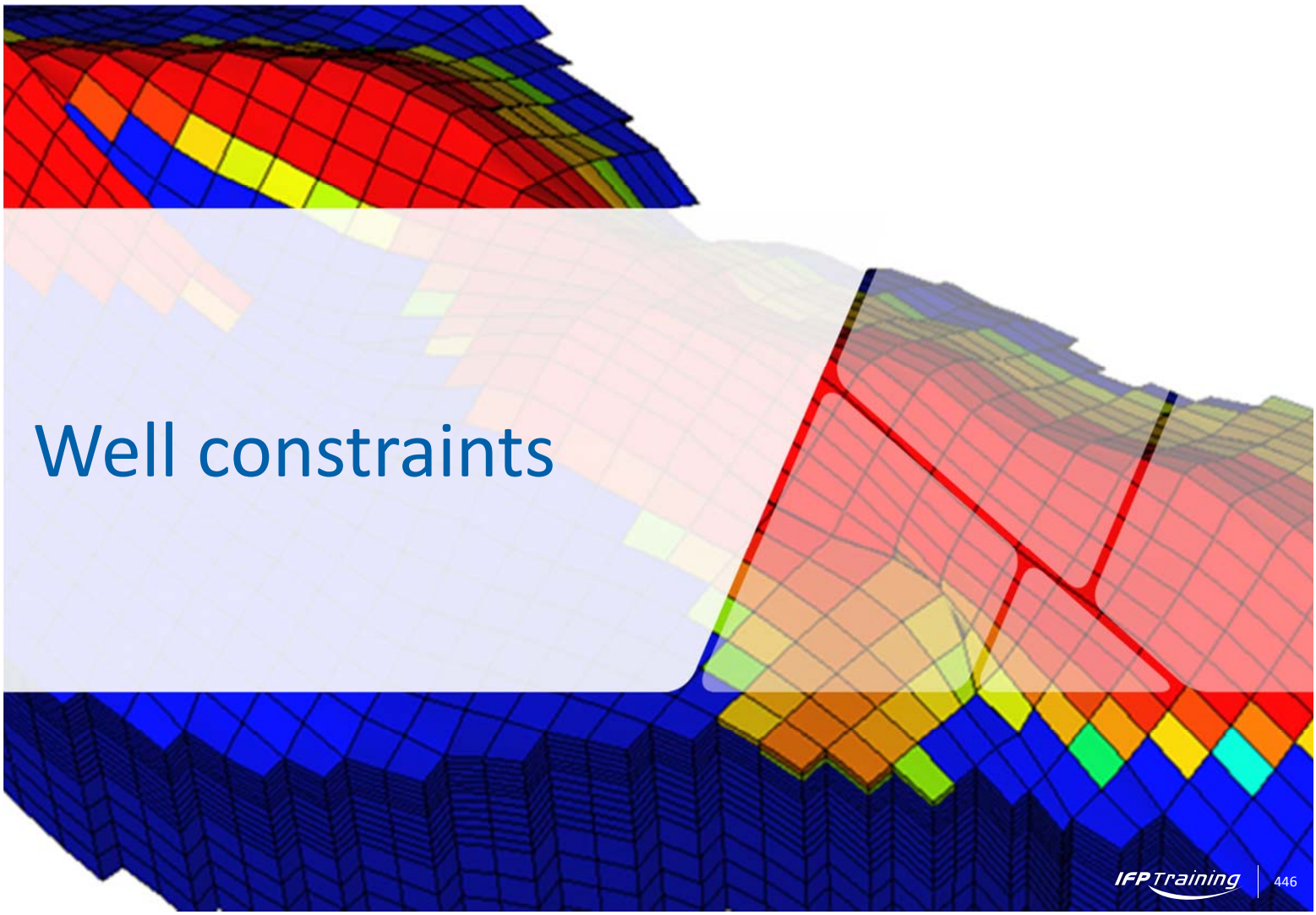
- **VFP tables are generally generated by well department**
- **It is recommended**
  - To use the PVT corresponding to produced fluids
  - To generate one table for each value of tubing diameter
  - To group wells according to their deviation, completion and produced fluid
- **The parameters must cover the range of values which will be reached during the forecast simulations:**
- **NO EXTRAPOLATIONS !**
- **If extrapolation, some BHP may correspond to a combination of parameters physically impossible.**
  - Values higher than the max reservoir pressure should be given to ensure that the well flowing conditions will not enter the forbidden region

Matching of well performance

- **Well performance parameters are:**
  - not used during history match (Wells are controlled in flow rate)
  - used during production forecasts (Well flow rates are directly linked to well performance)

- **During history match**
  - It is pointless to try to match BHP and THP as long as reservoir pressure is not matched
  - It is highly recommended to match BHP and THP as soon as reservoir pressure is matched by introducing the VFP tables and adjusting PI.

- **At the beginning of production forecasts**
  - BHP and THP must be matched per well to ensure the continuity from boundary conditions in flow (HM) to BC in pressure (forecast)



Well's constraints

Production Primary and Secondary Constraints

- **Primary controls**
  - Target rate of a principal phase
  - Fixed pressure: BHP or THP
- **Secondary controls**
  - Maximum rates of one or more phases
  - Maximum ratios (GOR, WCT, WGR)
  - Limiting pressures
  - Limiting DP
- **Simulator will operate the well under primary control unless one of the secondary constraints is offended**
- **Controls might be reset at any time during the simulation**

Production Primary and Secondary Constraints

- **In practice there is no real distribution between primary and secondary constraints**
  - Simulator will always honour the most constraining one
- **Example: if a well can produce 900 m3/d at BHP=30 bar**
  - Target rate 1000 m3/d subject to minimum BHP of 30 bar:
    - Well produces 900 m3/d at BHP = 30 bar
  - Target BHP = 30 bar subject to maximum rate of 1000 m3/d
    - Well produces 900 m3/d at BHP = 30 bar

- **Well controls**
  - Control data for production and injection wells
  - Economic limit data for production and injection wells
  - Well efficiency factors (for downtime)
  - Maximum drawdown per producer
- **VLP tables for production and injection wells**

Well controls in history match

- **In history Matching, observed average rates are known; controls are simple.**
- **VFP tables are introduced at the end of history matching process to ensure the continuity between matching runs (set measured Q) and prediction runs (limit THP).**

Simulator computations

- **Well dispatch of group constraints:**
  - evenly
  - as specified by the user
  - according to well potentials (PI)
- **Rate calculation for all phases using**
- **Pressure imposed:**
- **From Phead to Pbottom with pressure loss tables**
- **Search of stable functioning point: iterative process**
- **Rate calculation per phase and per perforated cell**

Group of well constraints

- **Hierarchy: Field, Platforms, Groups, Wells**

- **Constraints:**
  - On rates for main phase (economical, contracts, capacity)
  - On rates for secondary phase (capacity of flaring, water treatment) and gas lift rate
  - X-dependency: Qproduction = f(Qinjection), Pressure maintenance

- **Monitoring:**
  - Opening of waiting wells
  - Shut-in of most water flooded well

Field and numerical PI

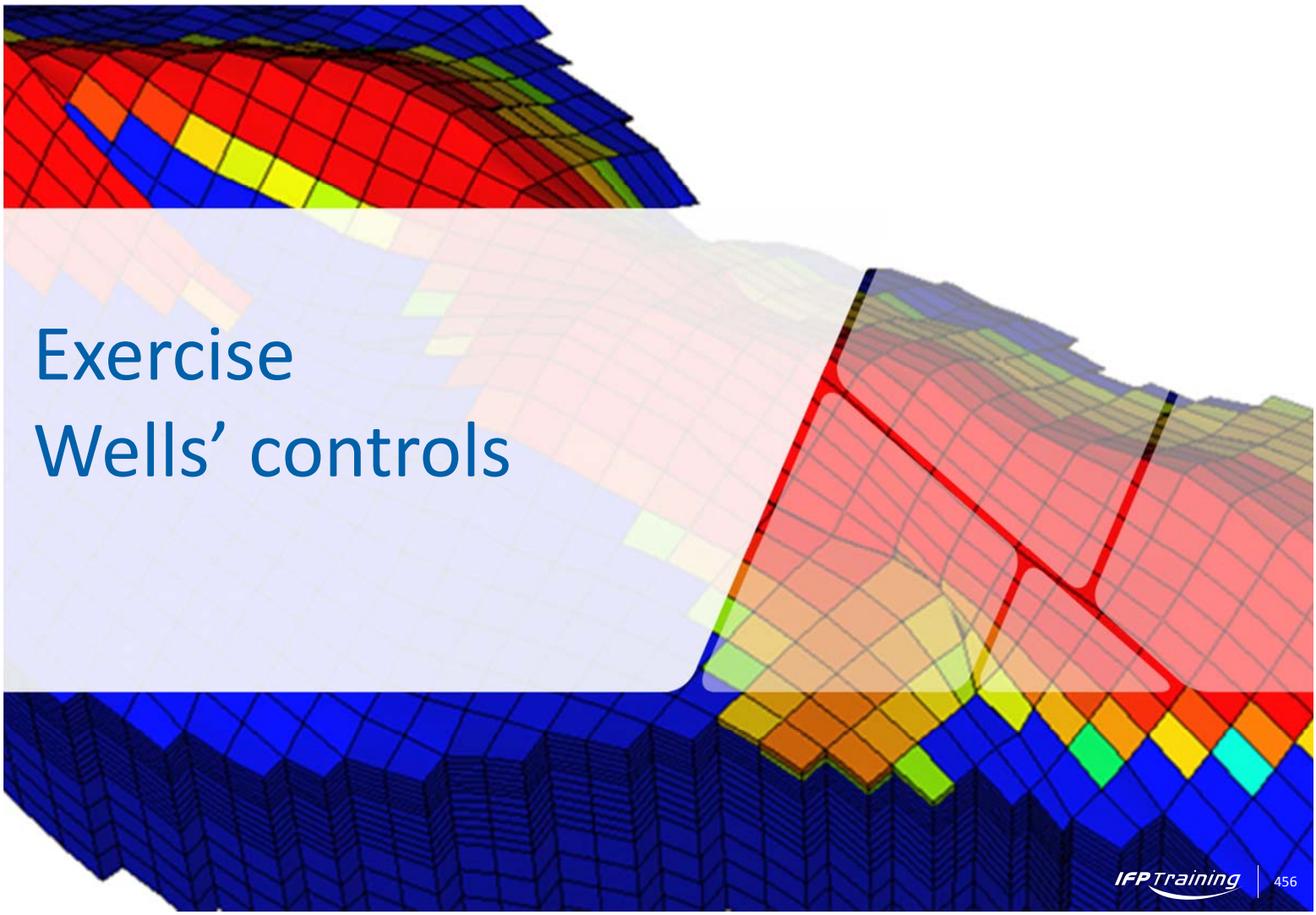
Exercise

- **Calculate the numerical PI and the field PI for a monophasic vertical oil well from the following data:**
  - Qo = 1000 Sm3/d
  - KH = 1000 mD.m and S = 0.5 from well test interpretation
  - rd = 1000 m
  - rw = 0.1 m
  - µo =0.7 cP and Bo = 1.2
  - The well is in a square grid of side 100 m and the formation thickness is 10 m
  - Interference test show a permeability anisotropy kx/ky = 0.5

- **If the bottom hole flowing pressure is 100 bar, calculate:**
  - Reservoir pressure at the drainage radius
  - The well grid block pressure (Pb) in the reservoir model

Keypoints to keep in mind

- **Main constraints for the simulator:**
  - Pressure target:
    - Maximum or imposed
    - WHP/BHP
    - Minimum for producer – maximum for injector
    - Maximum for some layers
  - Rate target:
    - Surface rates: Qo, Qg, Ql
    - Bottom: Qt (history match)
- **Secondary constraints for the simulator:**
  - Water cut
  - Gas oil ratio
- **Monitoring: actions when a constraint is offended: workovers?**



Exercise
Wells' controls

Discovery history

Courlis oil field was discovered in 1984 under 80-90 meter water at about 30 km from the coast line.

The first exploratory well, Courlis Marine 1 (CLM1), targeted a deep structure. During drilling, direct fluorescent and samples showed bitumen and residual oil before the targeted structure was reached. They were located in Cenomanian sands. Small gas indices were also found in Turonian carbonates and Senonian clay-rich sandstones.

A few kilometers from CLM1, a shallow anticlinal structure showed bright spot in the Senonian, a possible flat spot in the Cenomanian and a fuzzy zone near the top of the structure. Thus, it was decided to begin a high resolution seismic campaign and drill a second well, CLM2. This well showed oil reservoir in Cenomanian and Turonian series and gas in the Senomian which was very shallow. Furthermore, the water-oil contact was found in the Cenomanian at depth corresponding to the flat spot.

The structure area (18 km2), the good well productivity from CLM2 and the good reservoir characteristics for Cenomanian emphasized the interest of the discovery.

During the first quarter of 1984, 4 evaluation wells (CLM3, CLM4, CLM5, CLM6) were drilled to better define the structure boundaries and check that flat spot matches the water oil contact. From these wells, it follows that the flat spot was due to lithology changes. However, the structure size was confirmed. Gas was detected in the Senonian, oil in Turonian and Cenomanian reservoirs.

This exercise will only deal with the Cenomanian reservoir.

Cenomanian reservoir description

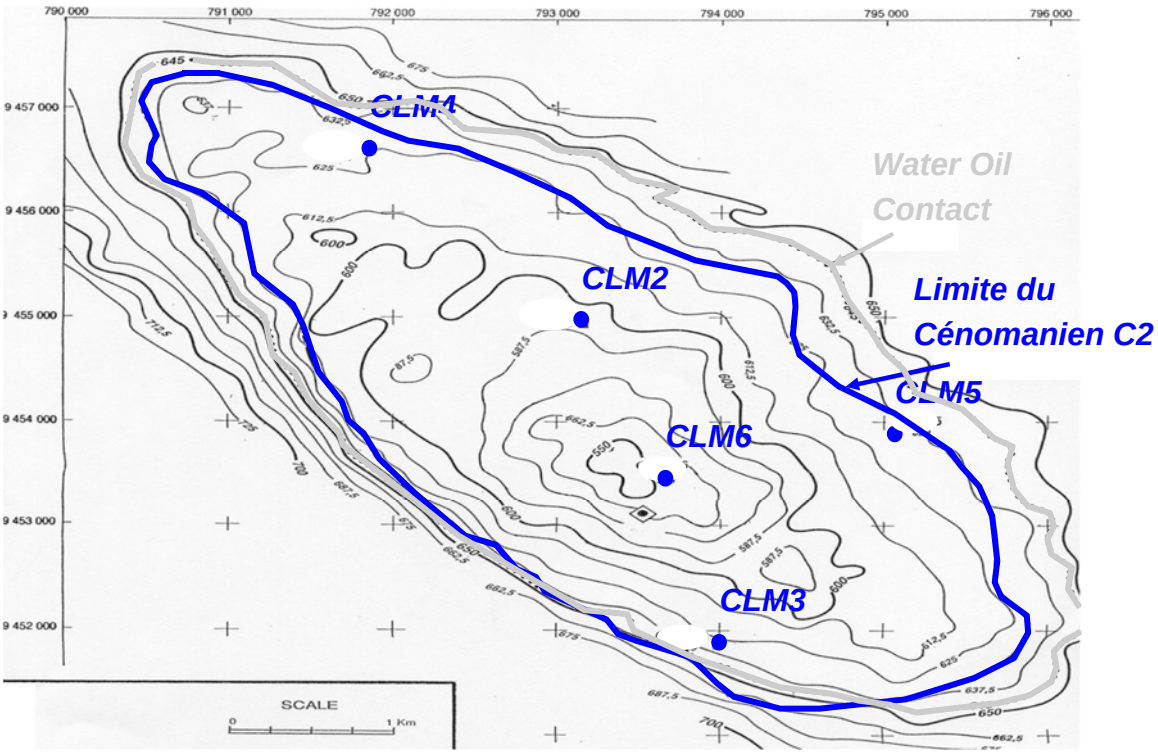
At the top of the Cenomanian, the structure is an anticlinal along a NW-SE axis with a narrow top graben. The reservoir top is at 550 mSL. CLM6 well was almost at the structure top. A slightly higher zone may exist North West of CLM6.

The Cenomanian reservoir has three level (C1 to C3). We are mainly interested in the top of Cenomanian series (C1 level) which is made of clean unconsolidated sands with fine to coarse grain inter-bedded with silt and shale. The top of Cenomanian reservoir (C1 level) is located at a depth of 545 mSS and the OWC is at 645 mSS. The thickness of C1 level varies between 10 and 45 m with a maximum near the centre of the structure.

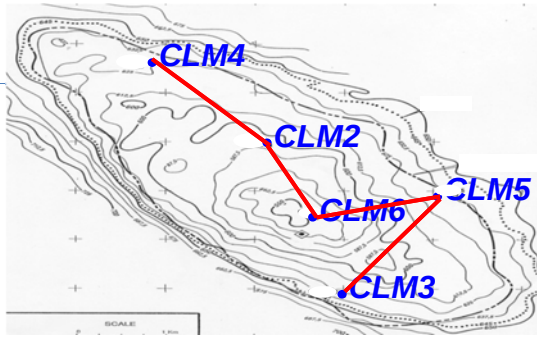
At varying depth from the top of the reservoir, the C2 level is made of thigh dolomitic sandstone with fine to medium grain sandstone both inter-bedded with shale. The thickness of this level varies but it remains quite compact. The C2 reservoir is quite thick at the centre (over 90 m). Its thickness decreases down flank to zero. It created the seismic amplitude variations at the Cenomanian top. This layer presents good quality sandstone but they are not continuous (see CLM2 log). The transition between this layer and sands is not well defined in CLM6 well. The C2 level is essentially oil bearing and core plugs (CLM3, CLM4, CLM5, CLM6 wells) show that this is an a priori tight level.

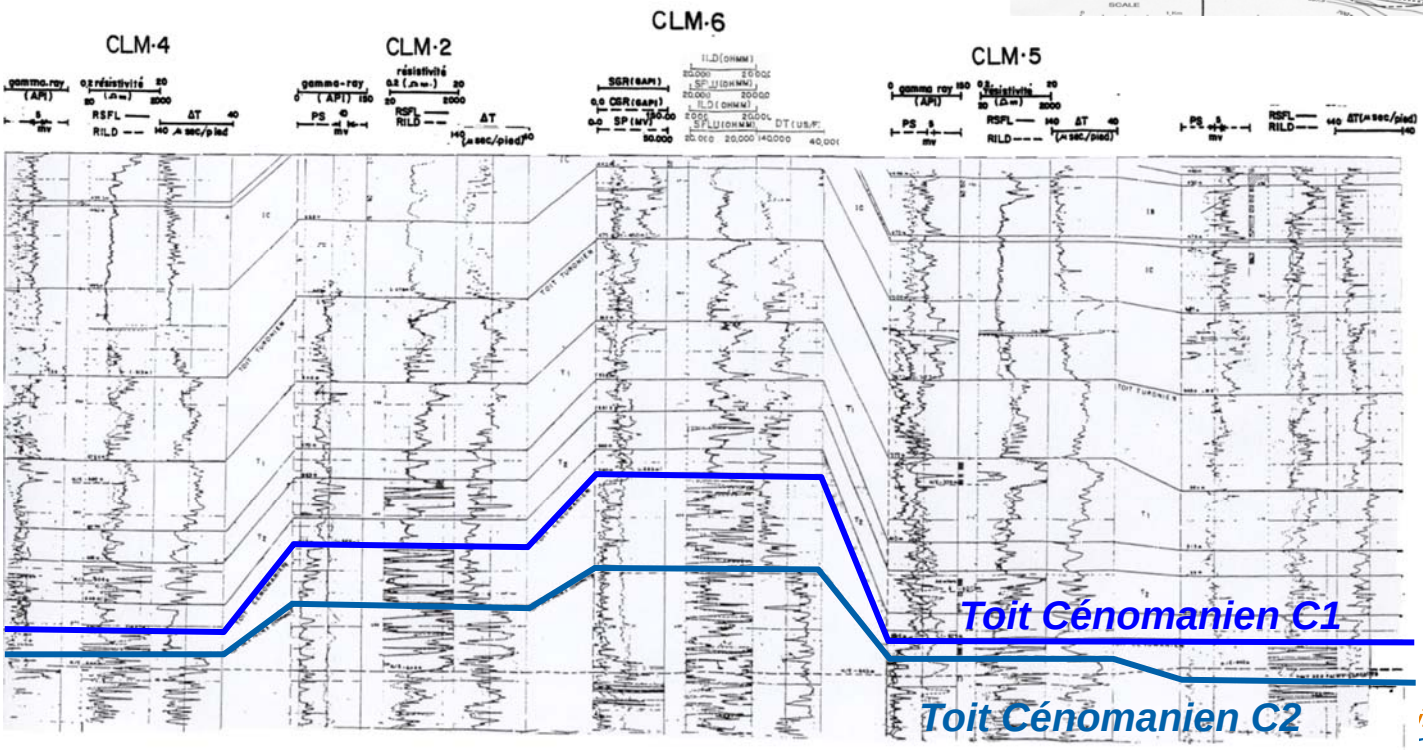
Under this C2 level, there are thick aquifer sands (C3 level). The aquifer reservoir C3 is about 250 meter thick. However the C1 reservoir is fully isolated from C3 aquifer due to the a priori tight dolomitic sandstone in C2 reservoir.

Isobathes top cenomanien



Log correlations





Reservoir characteristics:

Cenomanian petrophysical characteristics

- **Using log interpretations for CLM2, CLM3, CLM4, CLM5, CLM6, the geological study could establish correlation between these wells and a geological model was build for the field. Log interpretations yielded porosity and initial water saturation as showed in the following table:**

WELL	Top C1 reservoir (mSS)	Top C2 reservoir (mSS)	h_t (m)	h_n (m)	ϕ (%)	Swi (%)
CLM2	588	615.5	27.5	20	29	11
CLM3	629	648	19	15.5	28	11
CLM4	627	637	10	8	27	11
CLM5	629	637	8	6	26	11
CLM6	555	596.5	41.5	30	28	11

Fluid properties

- **Oil**

Property	
Reservoir temperature	46 ° C
Initial reservoir pressure	59 bar
Saturation pressure	57 bar
Oil formation volume factor	1.105 v/v
Solution gas @ Psat	32 v/v
Viscosity @ Psat	10.6 cP
Compressibility @ Pb	0.000109 bar^{-1}
Stock tank oil specific gravity	0.896

- **Water**

Property	
Water formation volume factor	1.01 v/v
Density @ 25° C	1.07
Viscosity	0.7 cP
Compressibility	0.000035 bar^{-1}

Initial conditions

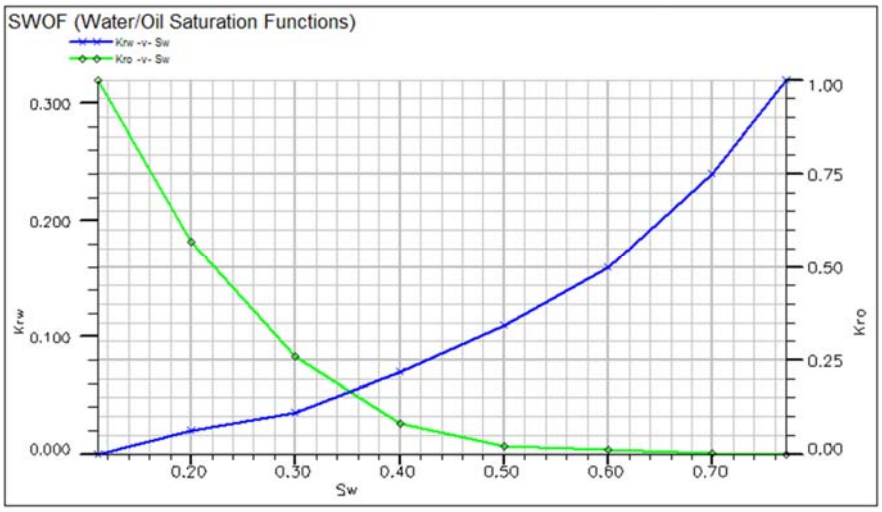
- **The initial reservoir temperature is 48°C and its initial pressure is 59.1 bar at the reference depth of 583 mSS. Therefore, the reservoir is slightly under saturated and there is no clear evidence of initial gas cap. Furthermore, no variation of bubble point versus depth was noticed. The initial water oil contact is at 645 mSS.**

- **Water-Oil and Gas-Oil relative permeability curves were estimated from similar reservoirs.**

- **Since the rock permeability is quite high, a hysterisis phenomenon on the capillary pressures was considered. The rock compressibility was estimated to be 5 10-5 bar-1.**

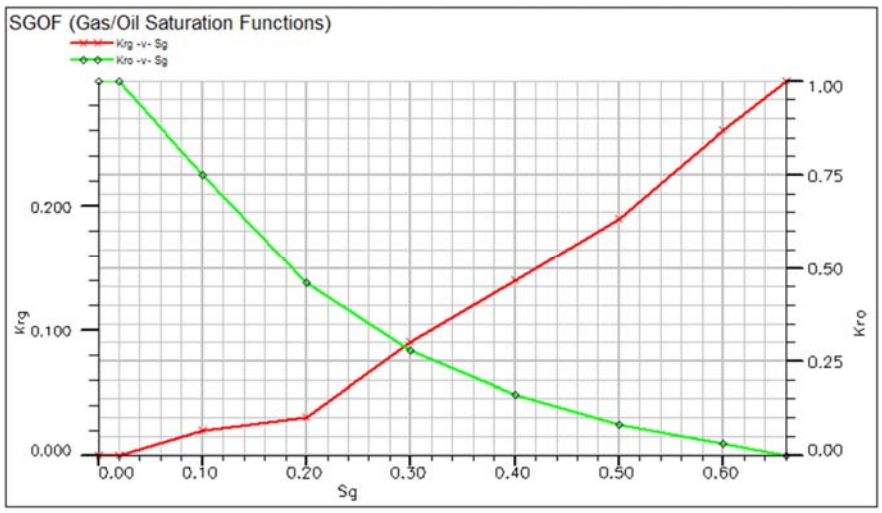
W/O relative permeabilities

- Irreducible water saturation Swc = 11%
- Residual oil saturation to water Sorw = 23%
- Relative oil permeability at Swckro = 1
- Relative water permeability at 1-Sorw krw = 0.32



G/O Relative Permeabilities

- Critical gas saturation Sgc = 2%
- Residual oil saturation to gas Sorg = 23%
- Relative oil permeability at Sgc kro = 1
- Relative gas permeability at 1-Sorg-Swc krg = 0.3



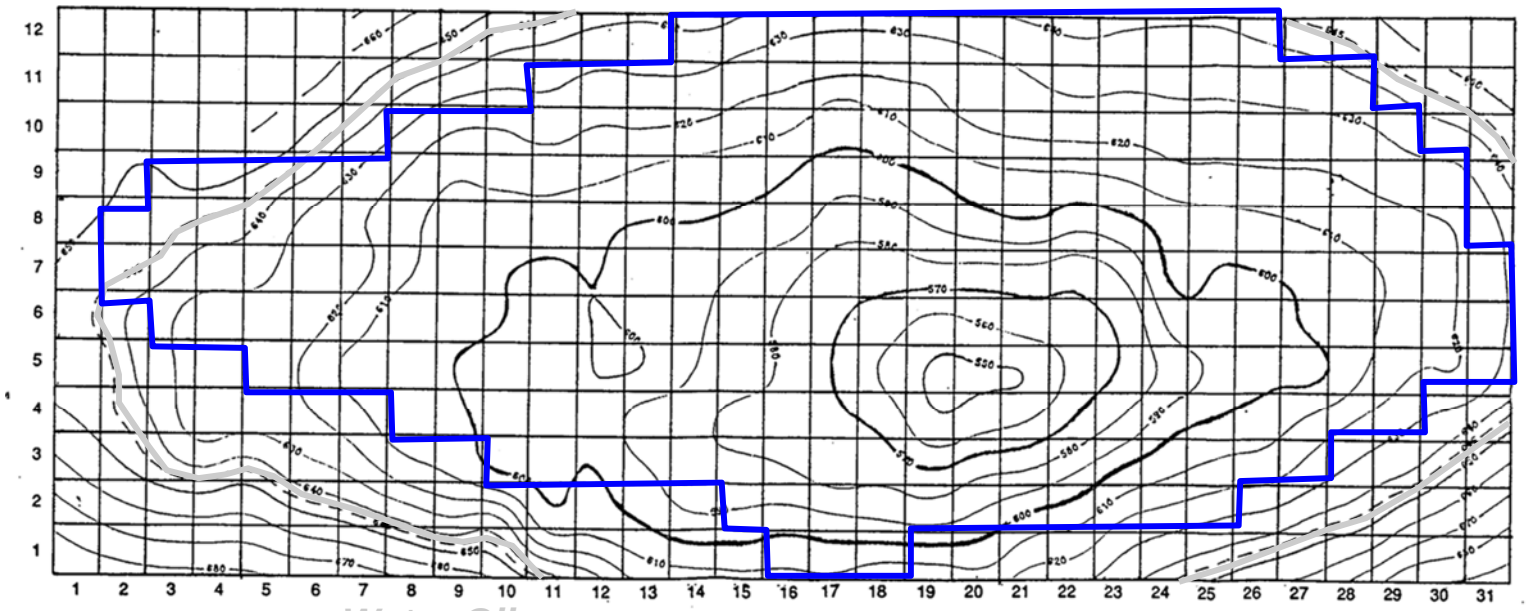
Numerical model

- In order to propose the development scenario, a 3D, 3-phase, black oil numerical model was built for the simulator. The horizontal grid which is oriented North East - South West is 31 by 12 in X and Y direction respectively. Each cell is 250 m by 250 m. Since no zonation was established in C1 reservoir, this level was divided in 3 equal thickness layers.

- Petrophysical characteristics and fluid data for the model are obtained from the previous information. They are already provided in the data file.

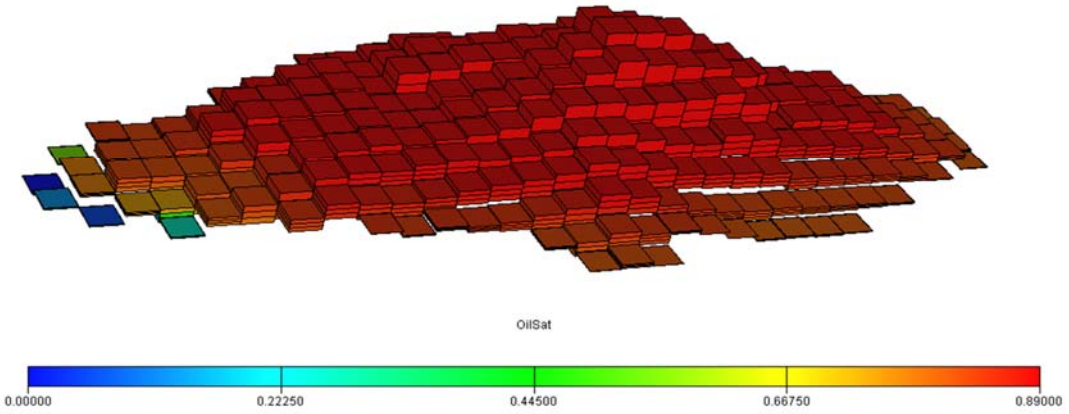
- Then you should propose development scheme through at least a primary production to satisfy an annual production requirement of 2% Initial Oil In Place as long as possible. However, during early development stages, production should be carefully planned to maintain reservoir balance. A 15 year production forecast is desired.

Grid-top reservoir



Maillage C1

Simulation grid (oil saturation)



3 layers, nx = 31, ny = 12 => 1100 active cells
No aquifer activity
Net to gross ratio: 0.75
Average porosity: 27%
Average Swi : 11%
Horizontal permeability: 1400mD
WOC @ -645 m
Top reservoir: -561 m

Project objectives

- **Initialize the numerical model.**
- **Compute the initial fluids in place in C1 reservoir.**
-
- **Several development schemes must be investigated for Courlis Marine Oil Field:**
  - Produce the field through natural depletion finding the optimum number of wells for this case. Make a sensitive study: Change Sgc to 10% and draw some conclusions.
  - Investigate secondary oil recovery using water injection: which is the main problem encountered.

Project constraints

- Wells are drilled from a maximum of 3 platforms A, B, C. The average well diameter is 81/2". Each platform has a maximum of 10 wells. Wells have a 31/2" tubing.
- For production wells, a 10 bar initial drawn down at sand face is the minimum needed to operate the well. No vertical flow performance tables are provided.
- Horizontal and vertical wells may be considered for production.
- Well drilling and completion take about 20 days. Two rigs are available during the initial field development. Wells are put on-line by group (4 wells per group).
- The bottom hole pressure is 25 bar for the producer during the natural depletion.
- The maximum admissible production GOR is 500 m3/m3 and the maximum allowable water cut is 95%. The minimum economical rate to operate a well is 5 m3/d.
- It may be necessary to optimize the perforation intervals to enhance recovery.
- Each well may produce up to 300 m3/d oil for a vertical well and up to 1000 m3/d for a horizontal one.
- For secondary recovery, sea water may be used since no compatibility problem exists. The fracturing pressure is 100 bar for this reservoir. The injection flow rate should be less than 400 m3/d and selected to optimize recovery.
- A minimum spacing of 500 m should be used between injection and production wells to avoid early water break through.

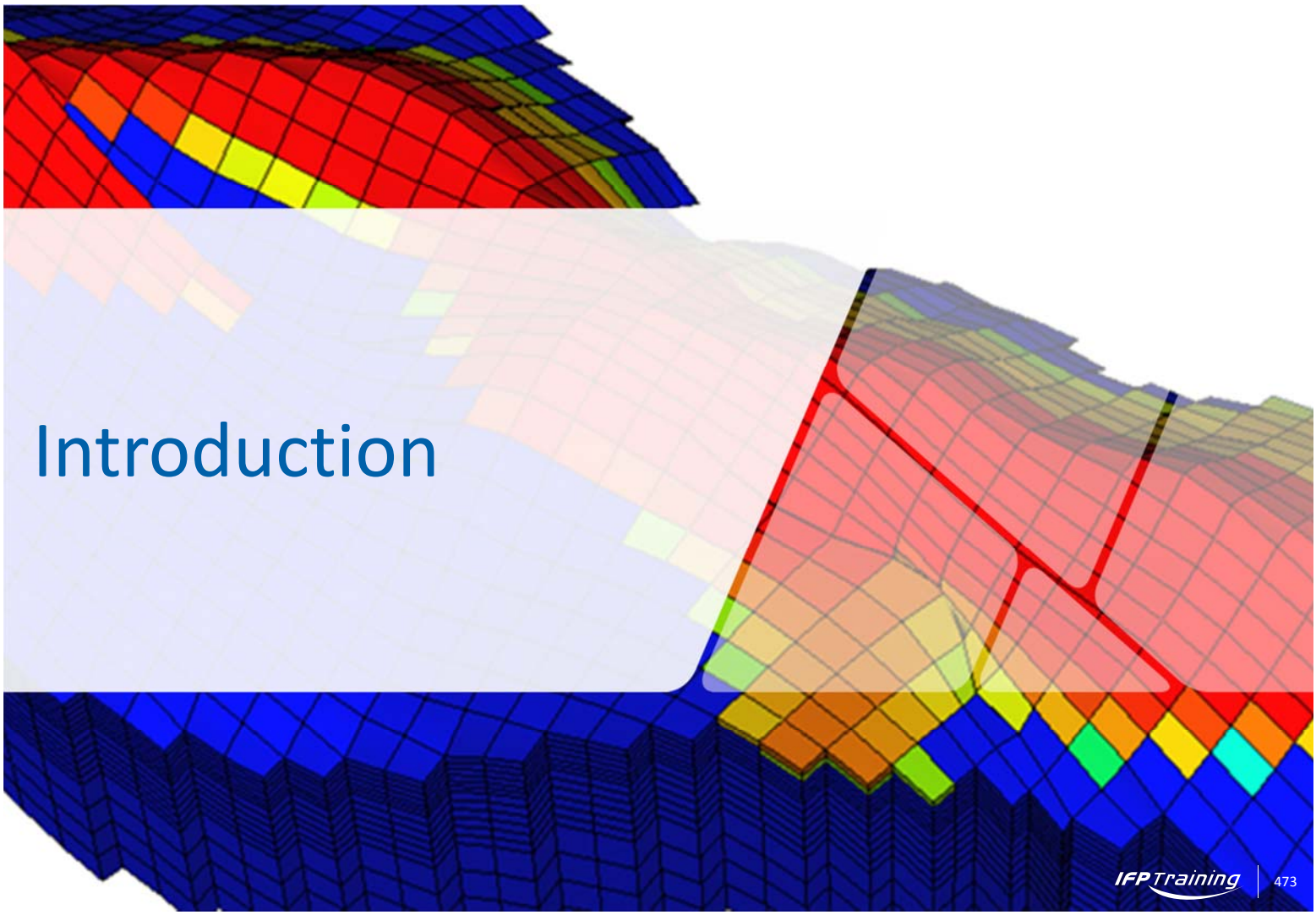


Reservoir simulation workshop
History match

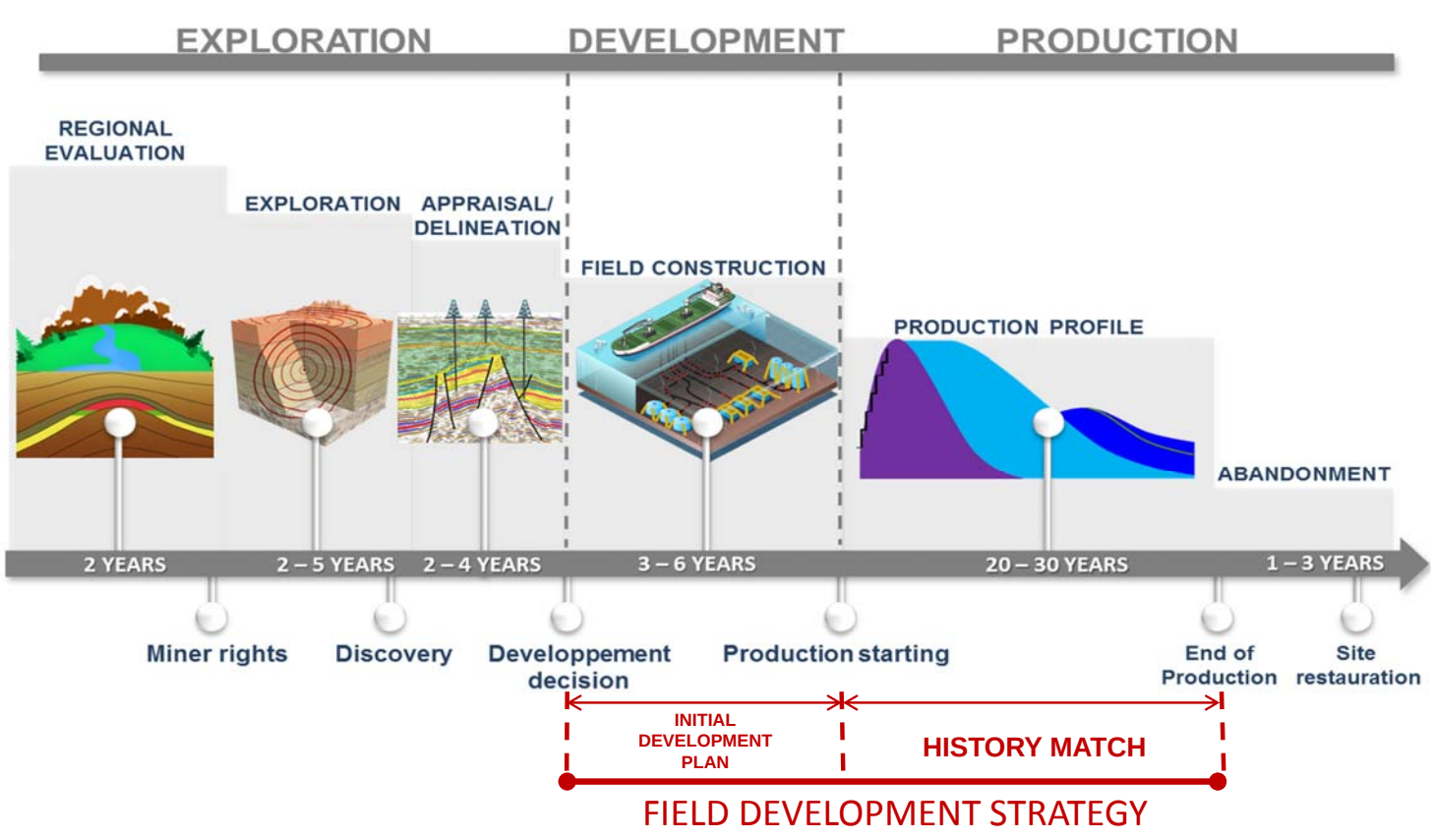
IFP Training

Sommaire

- Introduction 473
- Methodology 479
- Strategy 487
- Key features 497



Introduction



History match

Objective

- **Validate (Calibrate) the reservoir characterization by comparing performance of the model with historical performance (rates, pressures, saturations)**

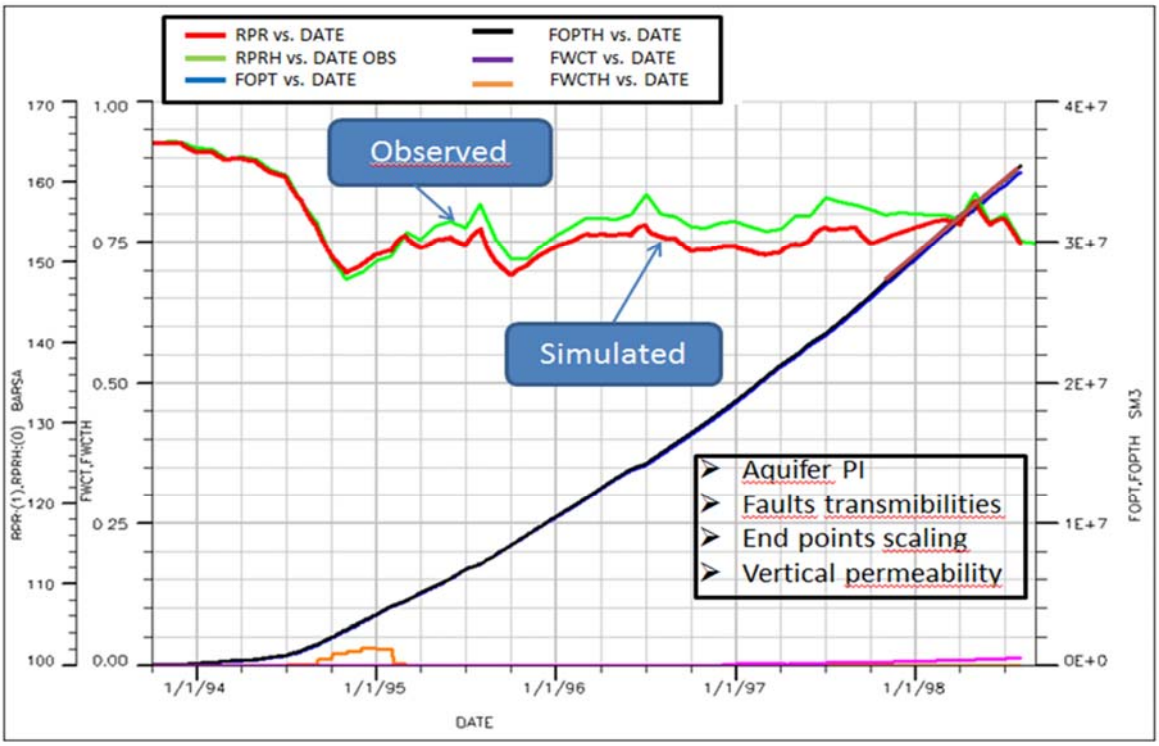
Principle

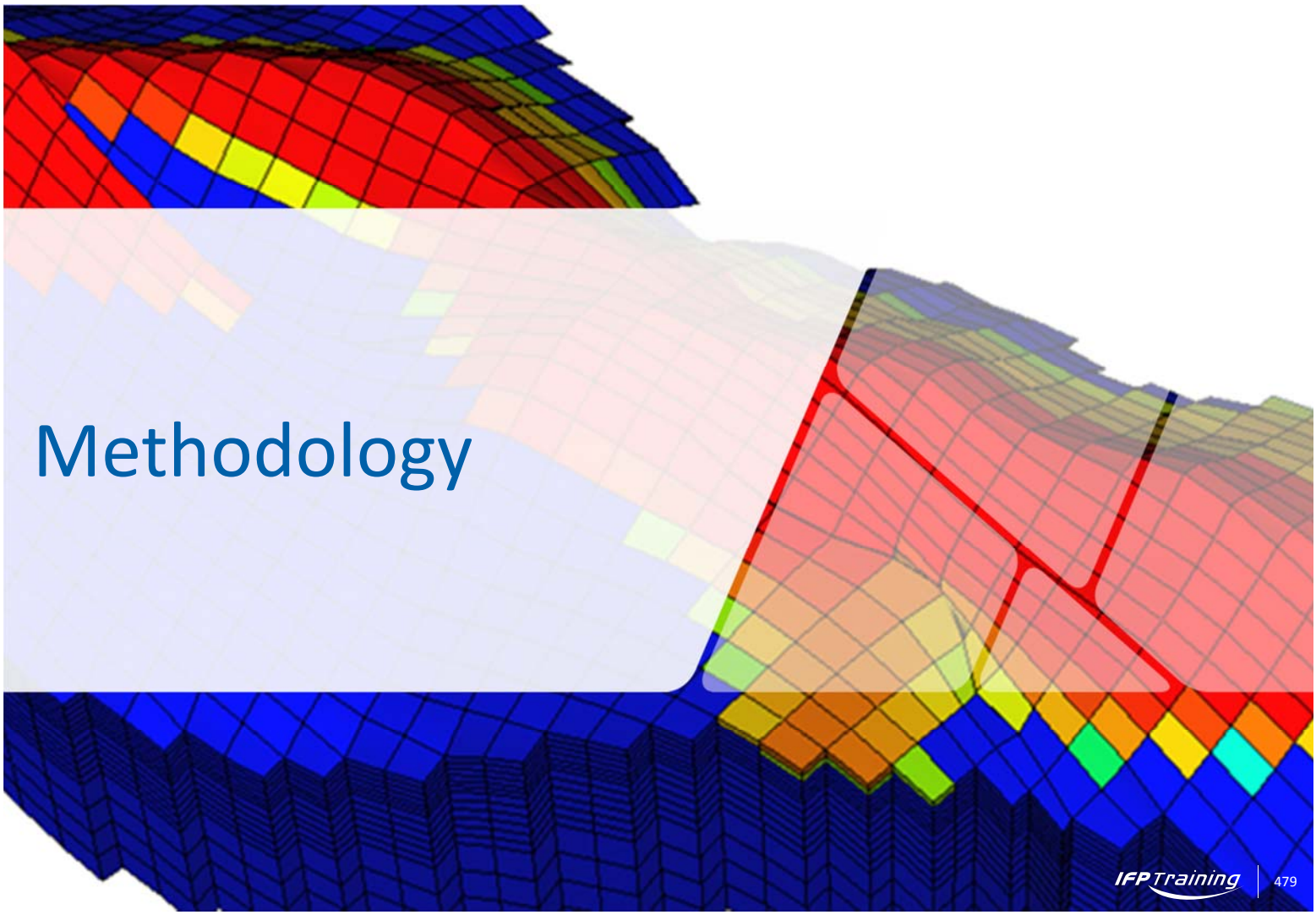
- **Reproduce with the model the measured evolutions of pressure, BSW and GOR by well, by zone or for the entire field**
  - If discrepancies appear during this comparison,
  - Modify the characterization in a rational way
    - Change uncertain parameters first (e.g. aquifer)
    - If necessary, change the characterization
  - Thus at the end of history match, the characterization should be improved
- **The history matched model can be used for prediction with more confidence**
  - Difficulties: uncertainties on fault and flow barriers network
  - Rule of thumb: predictions are reliable on a period twice the production period

History matching: main issues

- **Observed flows are imposed on wells during the history period**
- **One expect to reproduce:**
  - Pressure evolution
  - WCT and GOR
  - Gas or water breakthrough
  - WOC and GOC contacts
- **This is not a simple work as:**
  - Many data are unknown (little or no information is available at distance from wells)
  - It is not obvious to detect the most influent parameter (all parameter act together)
  - Some artefacts must be corrected (grid size, grid orientation…)
- **It is possible to distinguish between two main types of problems:**
  - Pressure match
  - Saturation match

History match



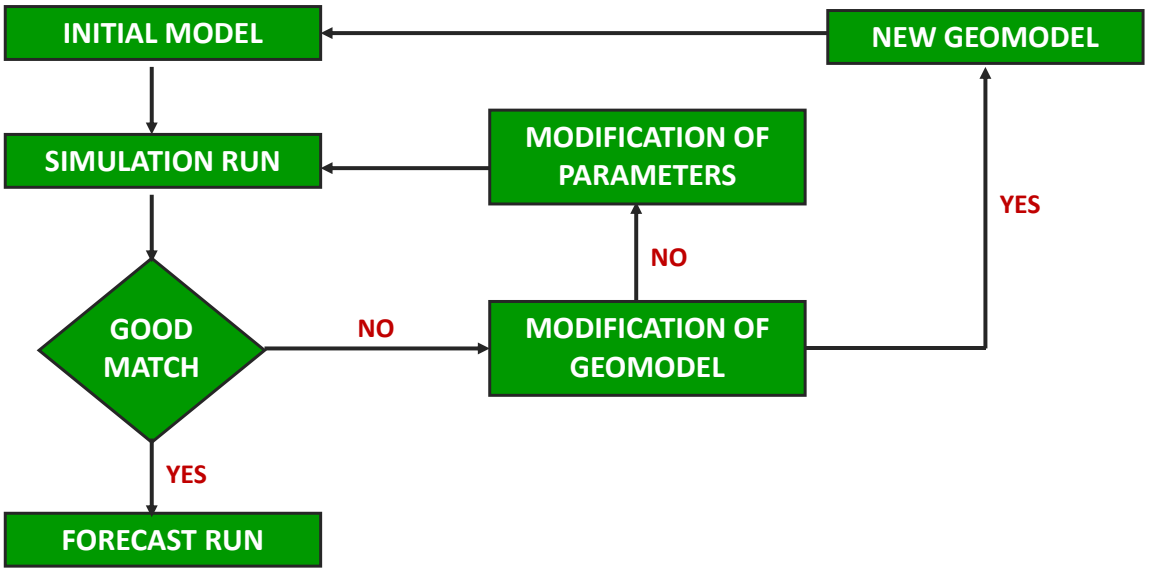


Methodology

History matching: methodology overview

- **4 main steps**
  - Step 1: Identification of available data that have to be matched
    - Adapt data to grid size
  - Step 2: Data Analysis
    - Identification of main uncertainty in the Geomodel
  - Step 3: Selection of matching parameters
    - Identification of probable range for each matching parameter
  - Step 4: Modification of matching parameters
    - Trial & error process
- **Reminder**
  - G&G must work hard to help the reservoir engineer to maintain the consistency of the geological model
  - It is better to have rough, consistent matching than matching which is accurate but destroys the model

History matching: schematic workflow



History match: data to match

Production Data – Well rates

- **Production data**
  - Field production (Oil, Gas and Water)
  - Allocated production per well (Oil, Gas and Water)
  - Allocated production per set of perforations (if PLT available)

- **Pressure data**
  - Type of pressure measurement
  - Timing and frequency of measurement

History match : data to match

Well rates

- **Determine the accuracy and frequency of measurements**
  - Which kind of separator (Gas-Liquid, 3 phase separator)
  - How is measured WOR, GOR if no 3 phase separator?
  - Frequency of measurements (weekly, monthly?)
  - Activity factor (% of activity of the wells)
- **Allocation of rates to perforated interval**
  - Completion and well status (casing, cement) to be known
  - Production logging is the best tool to allocate rate
  - If no production logging, estimate the accuracy of allocation to intervals
  - When possible, draw the maps of injected fluid breakthrough for each interval

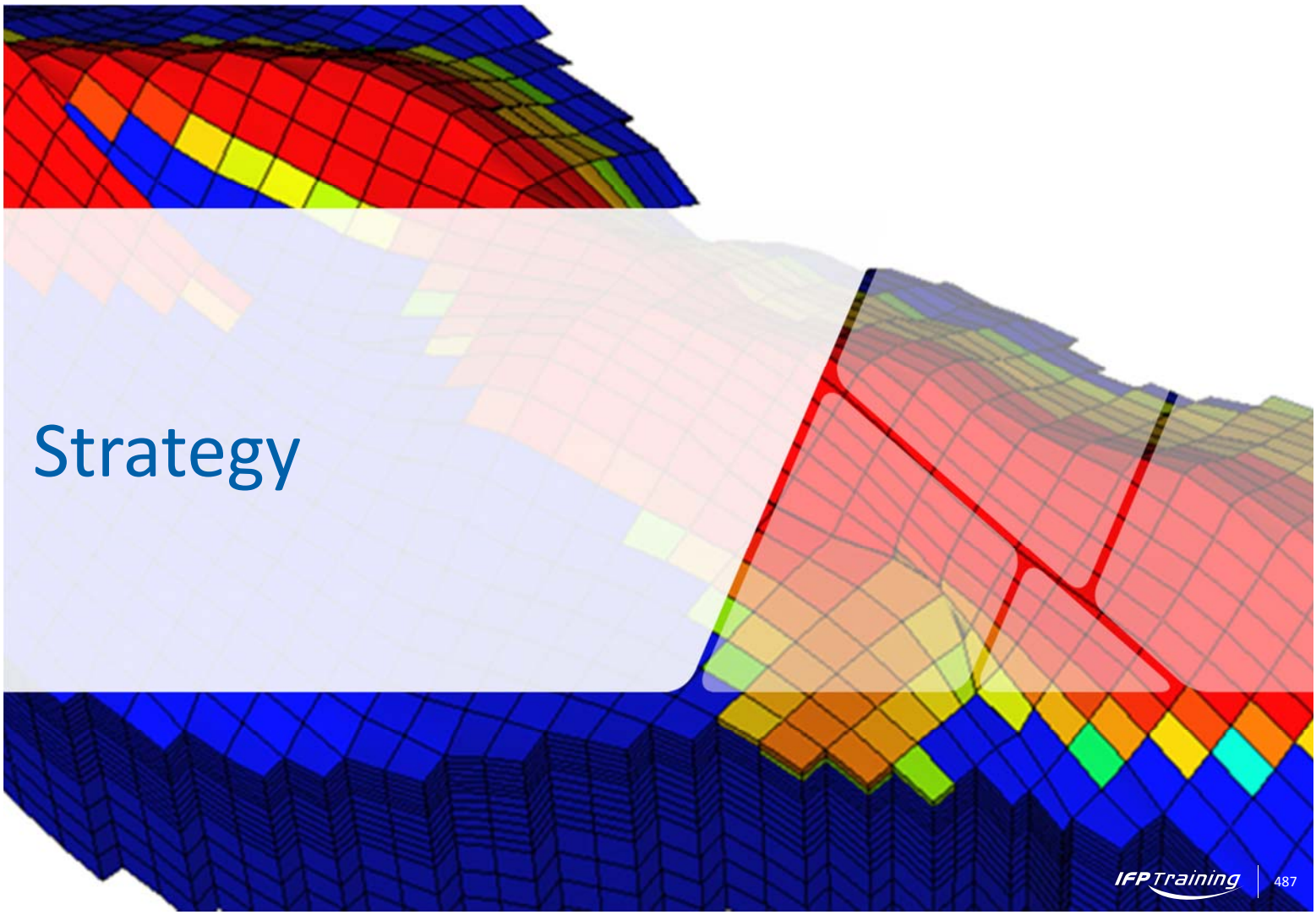
History match: data to match

Pressures – Saturations

- **Pressures**
  - Shut-in pressures of wells
    - Look at pressure curves to estimate the pressure in the cell
  - RFT in wells drilled after the start of production
    - Differential depletion by interval
    - Communication through faults
  - Observation wells
    - Shut-in wells should be changed to observation wells
  - WHP are usually not used
    - flow in tubing difficult to match exactly, interference with surface flow lines
- **Saturations**
  - Cased Hole logging, PLT, coring

History matching: some advice

- Start with a geological model
- Determine the level of uncertainty related to the different parameters
- At each step during the match process, note the influential parameters in order to limit the number of runs
- Use analytical model to evaluate the effect of each parameter and determine the most influent
- Take care with gridding effects
- Run sensitive cases for the influent parameters
- Adjust the primitive analysis when the match remains poor



Strategy

Field and well basis match

- **Field basis match:**
  - Faults
  - Aquifer
  - Global permeability scaling
  - Vertical Transmissivity

- **Well by well match:**
  - Local Transmissivity X, Y, Z
  - Relative permeability endpoint scaling (Swi, Sor)
  - Local PI and skin

History matching strategy

First phase: pressure match

- **Look at total fluid production and average pressure (kind of material balance)**
  - Of the whole field
  - Of parts of the field (compartments, or zones determined from the geological analysis, layers)
- **Change first the more uncertain parameters by zone**
  - Aquifer transmissibility (kh), storativity (kh ct)
  - Reservoir permeability
    - Multiplying factor to reproduce pressure gradients
    - Vertical connections to account for pressure discrepancies between layers (RFT useful)
    - Connections through faults to account for different pressure regimes

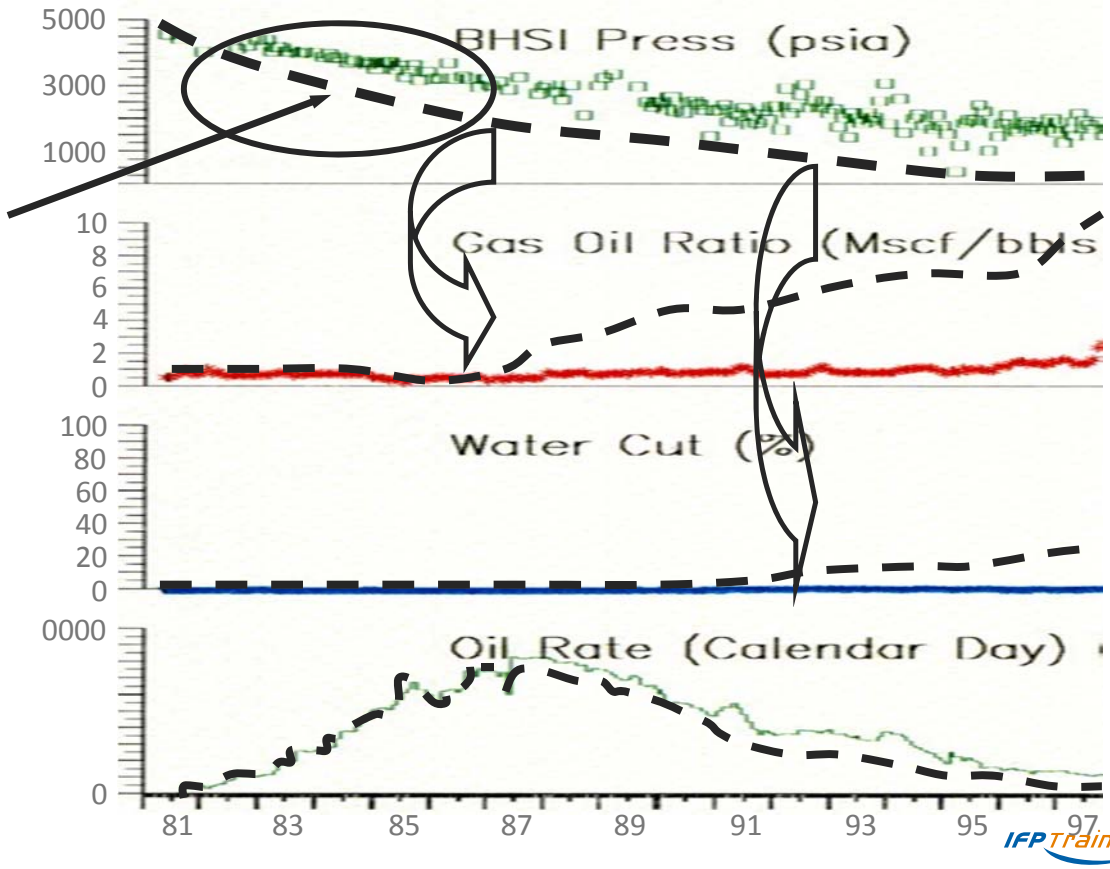
History matching strategy

Second phase: Fluid distribution (saturation match)

- **By zones (compartments, or zones determined from the geological analysis, layers) look at contacts movements, WOR and GOR of wells. Try to match fluid BT (break-through), fluid produced volumes**
- **Adjust first the permeability distribution**
  - Vertical distribution by layer and connection between layers (vertical permeability)
  - Areal distribution of permeability (barriers, high permeability zones, sealing or conductive faults)
- **Change Kr only if changes in permeability distribution cannot achieve a satisfactory match**
  - First check if initial water saturation is correctly represented
  - Look at the possibility of hysteresis

First step – General field match – Run 1

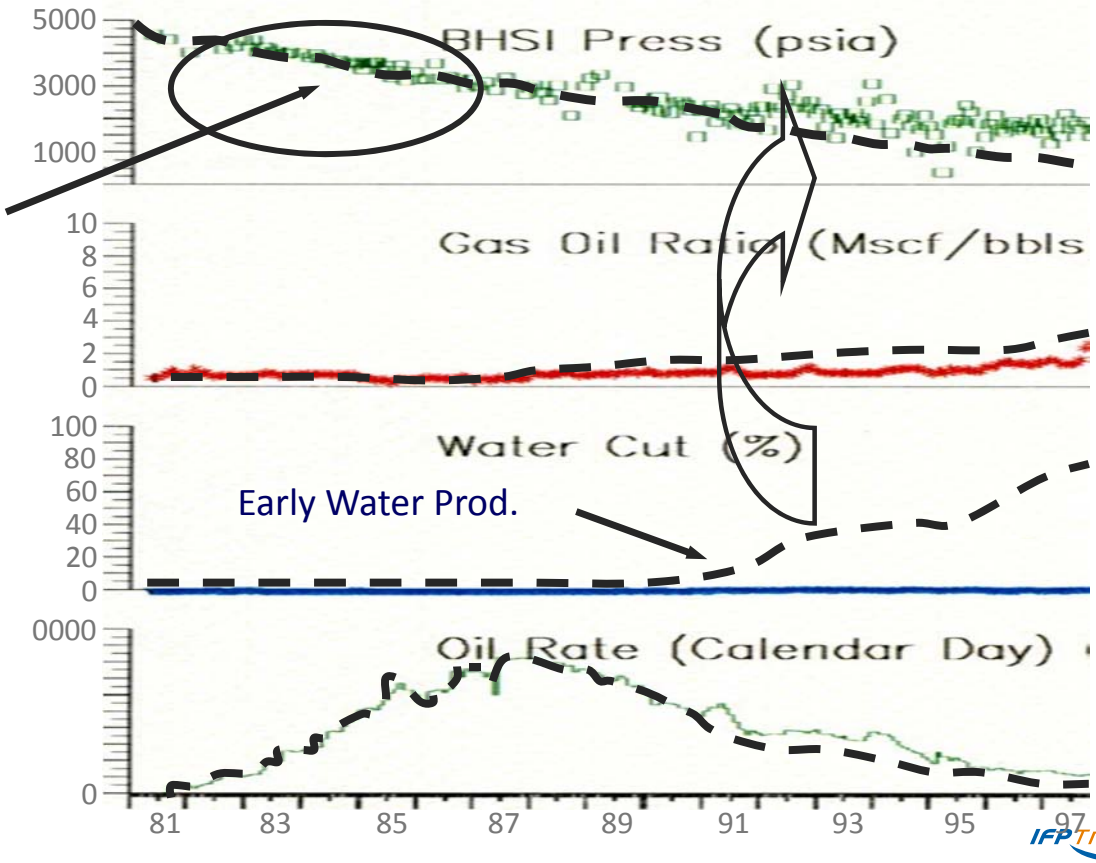
Wrong initial Pressure drop



Next step – General field match – Run 2

Aquifer potential increase

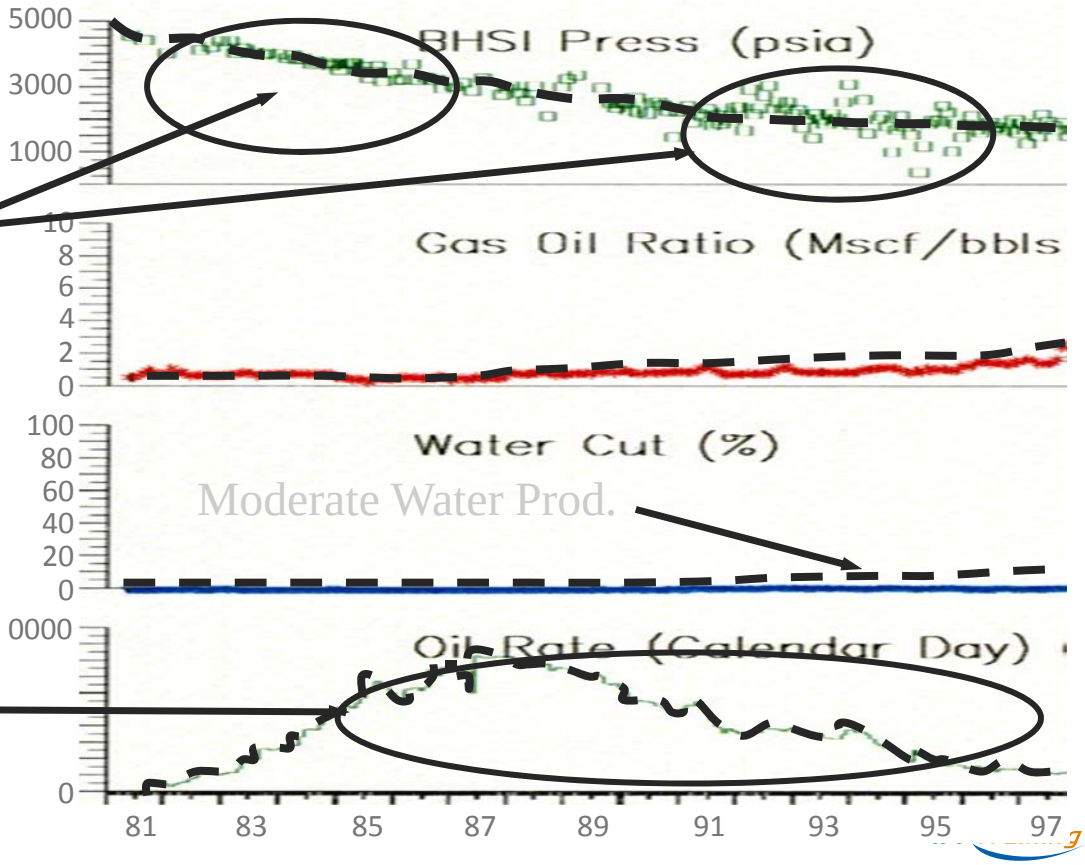
Good Initial Pressure drop



Final step – General field match – Run 3

Oil permeability increase

Good match of pressure profile



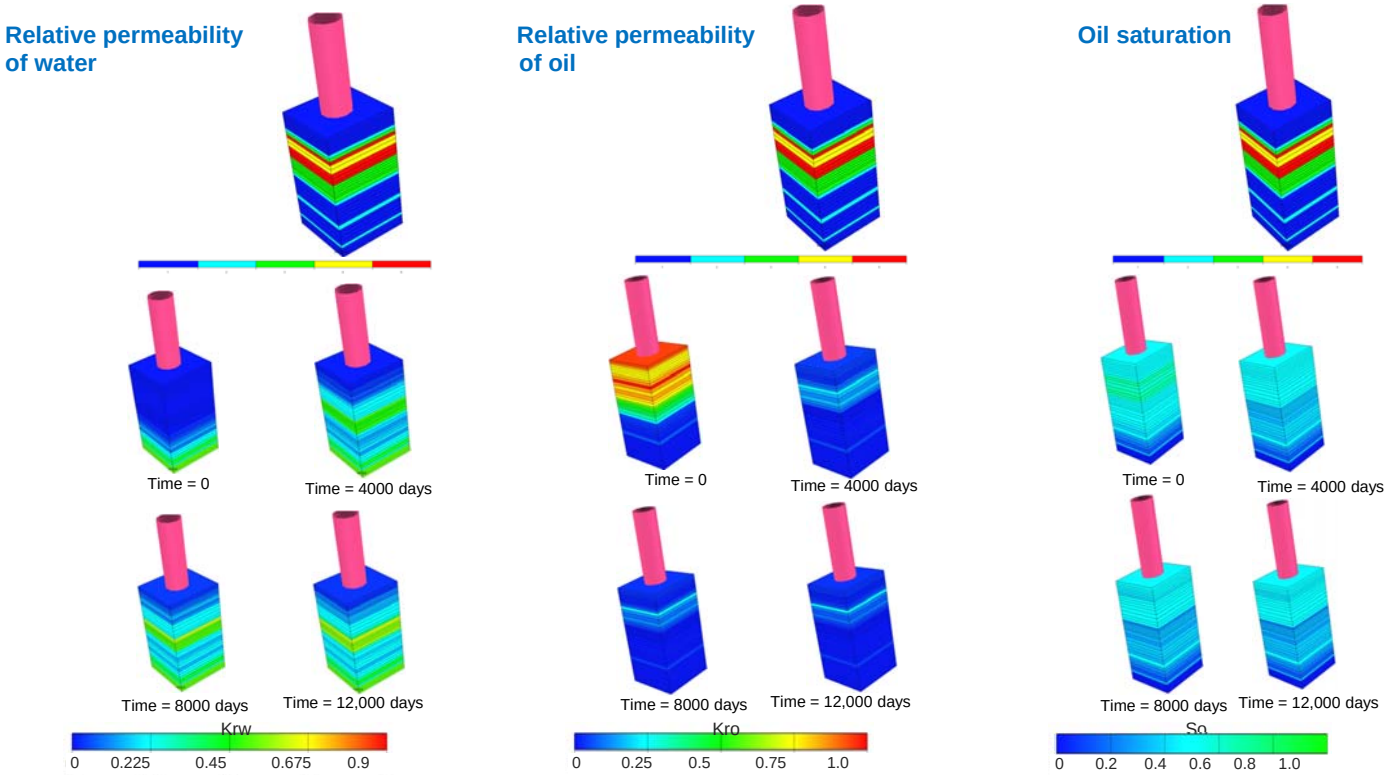
Oil production match

History matching strategy

- **Final step: well by well match**
  - Once the global and zonal matches are correct, look at each well
  - Check if the cell size is not the cause of an incorrect match
  - Check if coning can be suspected and is not taken into account by specific well Kr functions
  - Check if the discrepancy does not reveal a completion problem (cement or casing leak, fluid entry from another interval)
  - Corrections should remain in the vicinity of the well

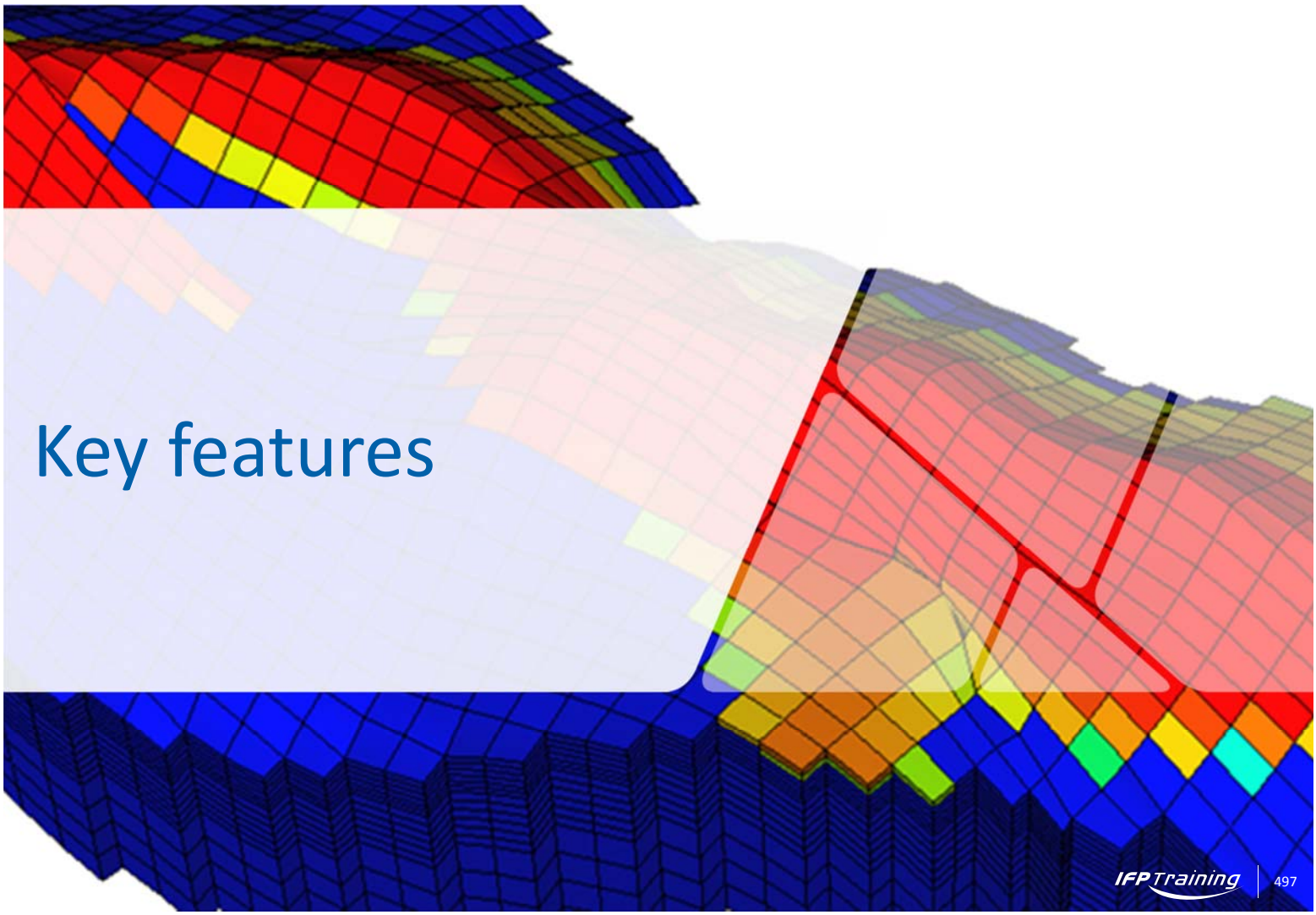
History matching strategy

Final step: well by well match



History matching: some advices

- **Flow directions are not correct if pressure is not matched**
  - Don't try to match saturations if you are not matched in pressure
- **Early well behaviour correspond to area close to the wells**
  - Concentrate on well data to match early production times
- **Late well behaviour correspond to area far from the wells**
  - Don't limit your analysis close to the wells to match late production times
- **Modification of matching parameters**
  - Try to anticipate model reactions by using simple calculations
  - Don't introduce new parameters without a look back to G&G



Pressure match: material balance

- **Objective**
  - Get a correct evolution with time of the average reservoir pressure
- **Main parameters**
  - Volumes Originally in Place
  - Aquifer size & water influx
  - Pore & Fluid Compressibility
- **Important notice**
  - The material balance should address the whole reservoir voidage (no material balance per fluid in surface conditions)
  - It is useful to get an energy balance to have an estimation of the importance of each individual production mechanisms (pore volume contraction, fluid expansion, water sweep, gas sweep…)

Pressure match: material balance

- **Pressure match is an adjustment of the reservoir energy balance between:**
  - Volumes originally in place
  - Aquifer activity
  - Pore and fluid compressibility

- **Reservoir voidage calculation**

$$Qres = Qo \cdot Bo + Qg \cdot Bg - Rs \cdot Qo \cdot Bg + Qw \cdot Bw$$

- **Important notice**
  - Reservoir voidage has to be calculated and is depending on the reservoir pressure
  - ECLIPSE keyword for reservoir voidage is RESV

Pressure match: Darcy's law

- **Objective**
  - Get a correct geometry of the flow lines and pressure drop along flow lines

- **Main parameters**
  - One phase flow
    - Transmissivity distribution
  - Multi phase flow
    - Transmissivity distribution
    - Transfer functions (relative permeability & capillary pressure)

Pressure match

Diffusivity equation

Objective: Get a correct evolution of reservoir pressure versus time and space.

- **Diffusivity equation:**

$$\frac{\partial^2 P}{\partial x^2}+\frac{\partial^2 P}{\partial y^2}+\frac{\partial^2 (P-\rho \cdot g \cdot z)}{\partial z^2}=\frac{K}{\phi \cdot \mu \cdot c}\frac{\partial P}{\partial t}$$

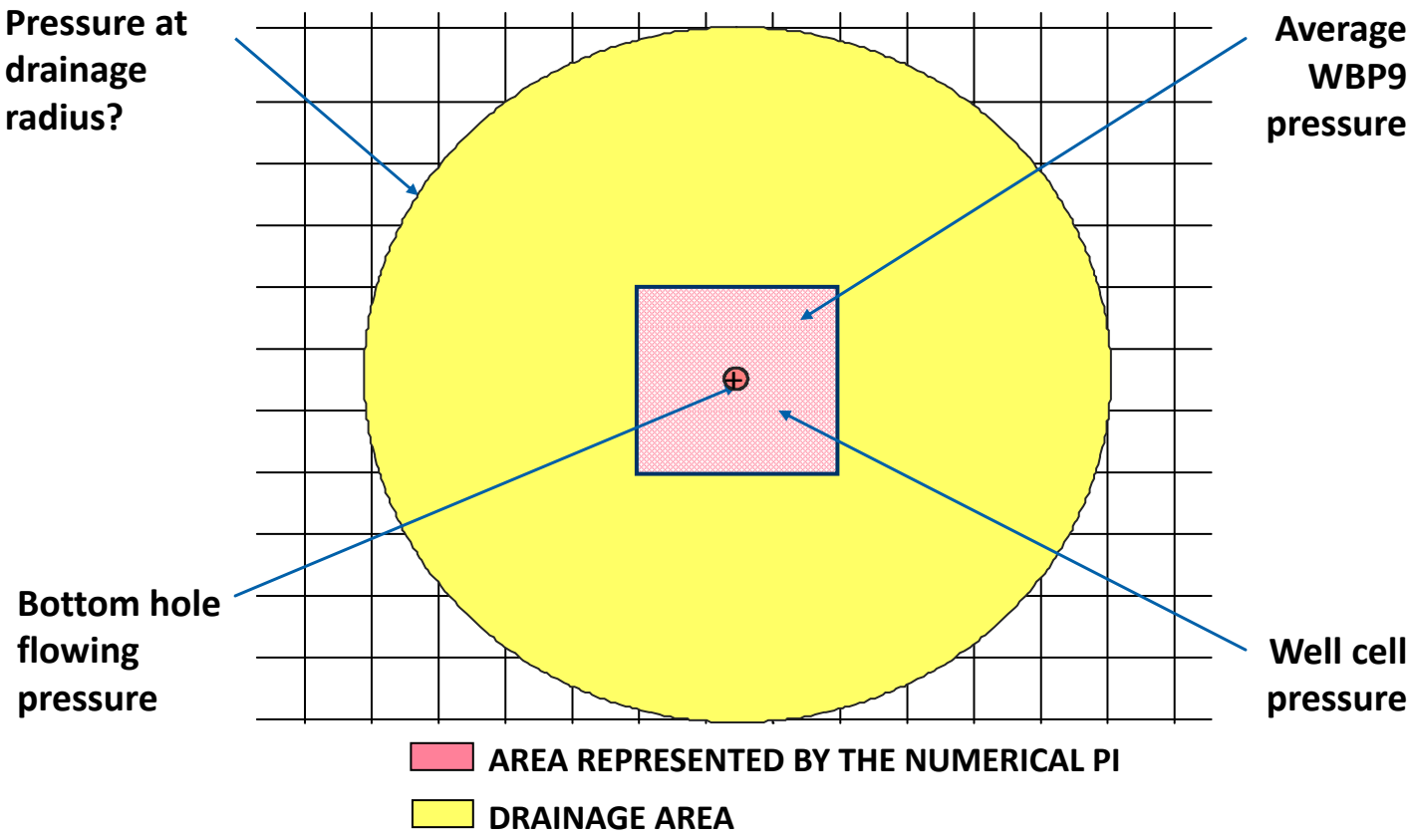
- **Main parameters:**
  - hydraulic diffusivity, K/(ϕ.μ.c)
  - permeability, K
  - fluid viscosity, μ
  - porosity, ϕ
  - total compressibility, c

Pressure match: wells' representation (1)

- **Objective**
  - Get a correct relationship between flow rate, reservoir pressure and bottom hole flowing pressure

- **Main parameters**
  - Numerical productivity index
  - Drainage area properties
    - Transmissivity distribution
    - Transfer functions (relative permeability & capillary pressure)

Pressure match: wells' representation (2)



History match strategy

- **First phase: pressure match**
  - look at total fluid production and average pressure (kind of material balance)
    - of the whole field
    - of parts of the field (compartments, or zones determined from the geological analysis, layers)
  - change first the more uncertain parameters by zone
    - aquifer transmissibility (kh) , storativity (kh ct)
    - reservoir permeability
      - multiplying factor to reproduce pressure gradients
      - vertical connections to account for pressure discrepancies between layers (RFT useful)
      - connections through faults to account for different pressure regimes

History match strategy

- **Pressure match parameters are:**
  - Depending on hydraulic diffusivity $K = k / \Phi\mu c$
    - Mobility k / μ
    - Porosity Φ
    - Compressibility c
  - External gridding limit conditions (aquifers, flow transfer …)
  - Pstatic evolution with withdrawal → adjustment of Φ and c ($\Delta P = 1/c * \Delta V/V$)
    - Increase of Φ or c => ΔP decrease)
  - Pstatic - Pflowing evolution → adjustment of k/μ (Darcy)
    - Increase of k/μ => ΔP decrease

Pressure match

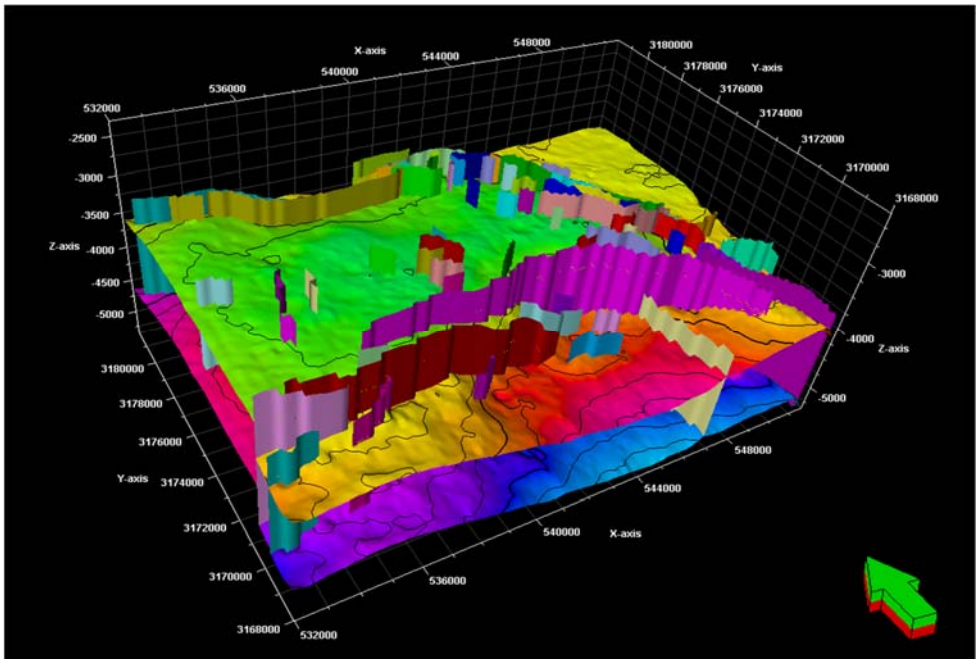
Aquifer activity

- **A preliminary study with a MB software is necessary to run the aquifer match. The expected result is the aquifer volume plus its permeability.**
- **The aquifer volume is to be reproduced in the reservoir model with aquifer cells or analytical functions.**
- **Aquifer activity needs to be adjusted in order to reproduce the field observed reservoir pressure history.**
- **The reservoir model production history is run with all the producing wells governed by the "reservoir voidage" option.**

Pressure match

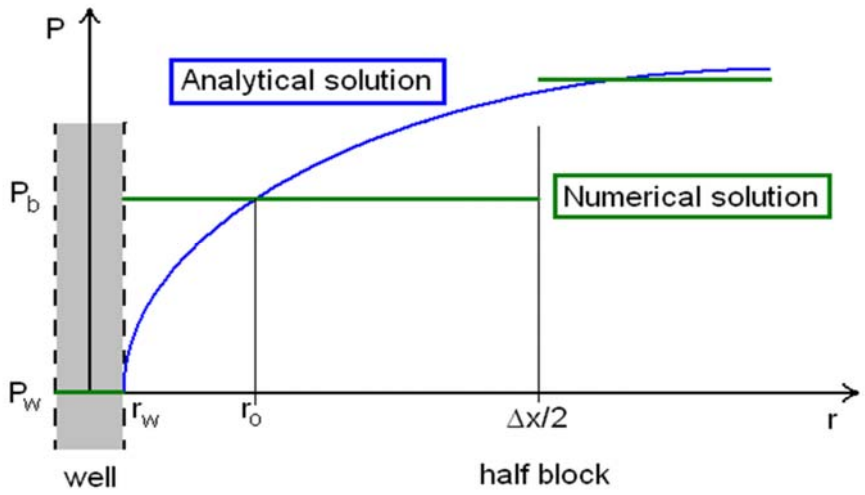
Fault modelling

- **Fault modelling: Only faults with influence in the zone of interest are modeled.**
  - definition
  - transmissivity



Pressure match: wells' representation

Numerical PI – Analytical vs numerical solution



$$CF_{well} = \frac{2\pi \cdot K \cdot h}{\ln(r_o / r_w) + S}$$

$$CF_{well} = \frac{\mu_{pb}}{kr_p(S_{pb})} \cdot \frac{q_{pwell}}{(P_b - P_w)}$$

Flow rates match

- **During the pressure match procedure, production rates are not honoured.**
- **Simulation is now run by setting the oil rate for producers so bottom hole flowing pressure, gas and water rates are calculated by the simulator.**
- **The phase rate matching consists of adjusting the calculated GOR and WCT to the field measured values.**
- **To honour the relationships between reservoir pressure, BHFP and phase rates, PI need to be adjusted. This is accomplished by applying multiplication factors to the well perforation connection values: MULTPI.**

Flow rates match

- **Main parameters:**
  - Permeability – Transmissivity.
  - Permeability barriers (i.e. faults)
  - Relative permeability: shape and endpoints.

Flow rates match

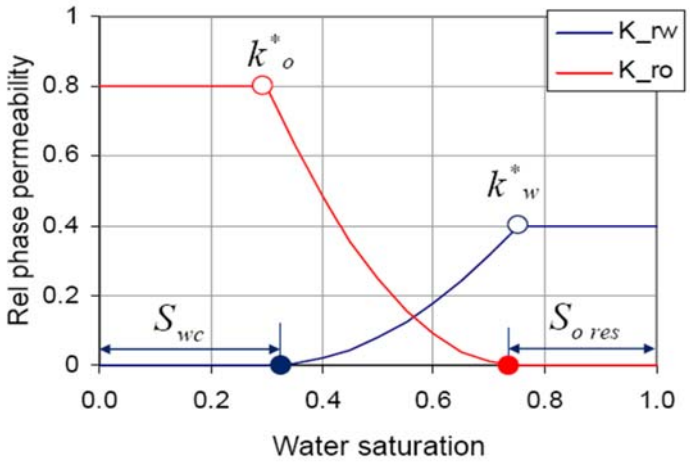
Relative permeabilities

k^*_o – end-point relative permeability for oil

k^*_w – end-point relative permeability for water

S_{wc} – connate water saturation

$S_{o\,res}$ – residual oil saturation



Anatoly Zolotukhin,
Statoil, 2004

Flow rates match

Remind: Endscale option

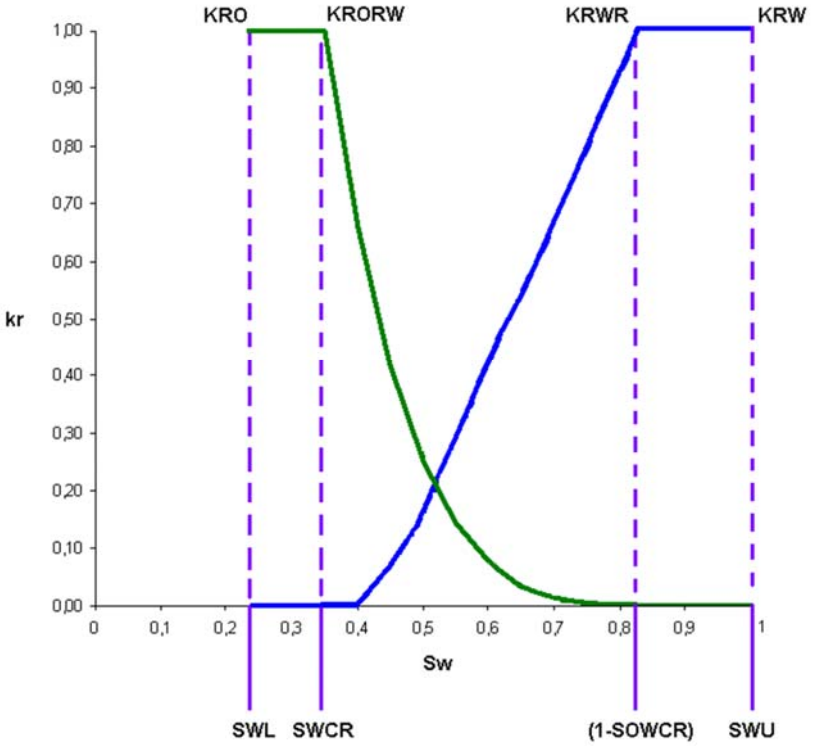
- **Objectives**
- **Modify relative permeabilty tables in an easy way, kr tables are normalized and remain always the same, only the end-points are changed and kr curves are then recalculated.**
- **It's a useful option in History Match simulations.**

Flow rates match

Remind: Endscale option

KEYWORDS

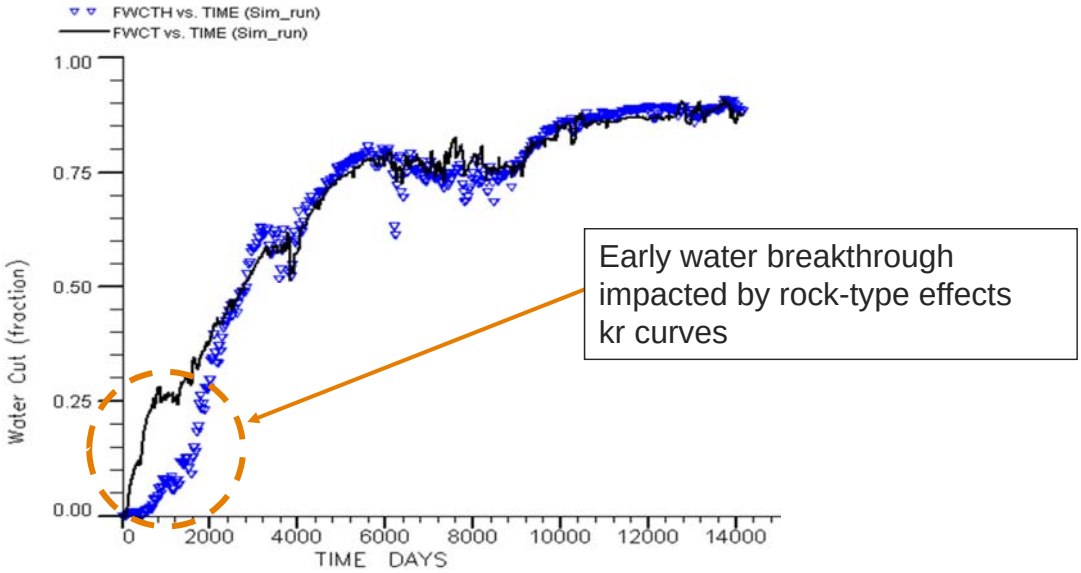
- KRO: Maximum oil relative permeability
- KRORW: Oil relative permeability at critical water saturation Swcr
- KRWR: Water relative permeability at residual oil saturation (1-Sowcr)
- KRW: Maximum water relative permeability
- SWL: Connate water saturation
- SWCR: Critical water saturation
- SOWCR: Residual oil saturation
- SWU: Maximum water saturation



Flow rates match

Relative phase permeabilities

- Water cut (WCT): water – oil ratio
- Water breakthrough (WBT): water production starts – associated to Swi



Flow rates match

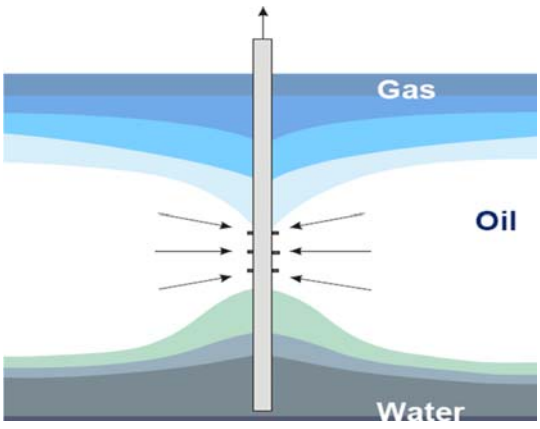
Water breakthrough

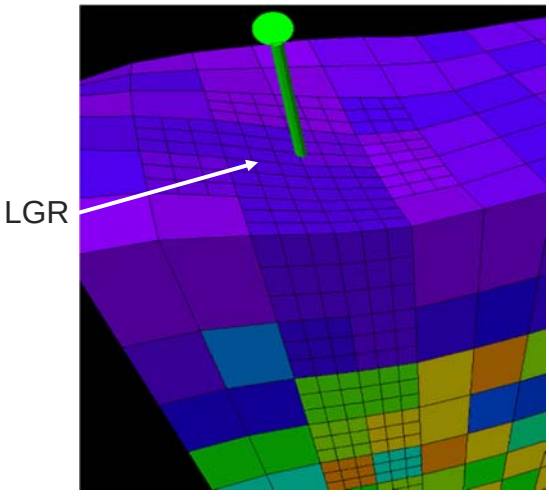
- Matching breakthrough times is a difficult task.
- Breakthrough times are sensitive to truncation errors (numerical dispersion) and the accurate matching requires finer grid than normally necessary.
- Using a LGR is a possibility to the use of pseudo-relative permeabilities can help.
- An unsuccessful attempt for a match indicates that some of the basic assumptions of the model (geology, structure, volumes, extensions, PVT behaviour, energy balance between initial hydrocarbon in place and aquifer activity) may have to be revised.

Flow rates match

Water breakthrough

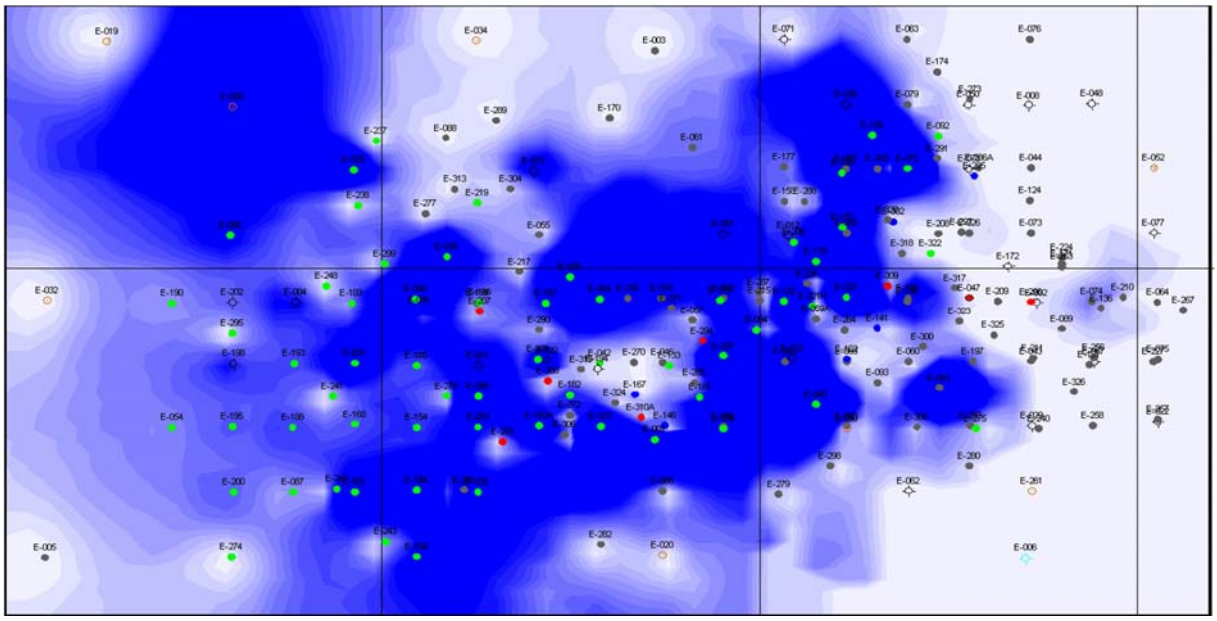
- The gridding techniques include local gridding (LGRs) for the creation of small cells around wells for improved resolution, useful to match the water breakthrough and water cut when conning effects are present.





Flow rates match

Water breakthrough



Cumulated Water (bubble diagram from OFM)

Uncertainty contributions

- Seismic interpretation
- Geological interpretation
- Well production allocation
- Observed data (bottom hole pressures, well logs, etc...)
- Fluid models
- Simulation grid accuracy (e.g. fault juxtapositions), orientation, etc.
- General poor control outside the main reservoir structure (aquifer support etc...)

Key points to keep in mind



- Keep a coherent geological model
- Do not match one parameter while ignoring the others
- Do not discard data which do not match!!!
- Avoid multiplying the Kr curves
- Do not look for a perfect match

Be very patient!

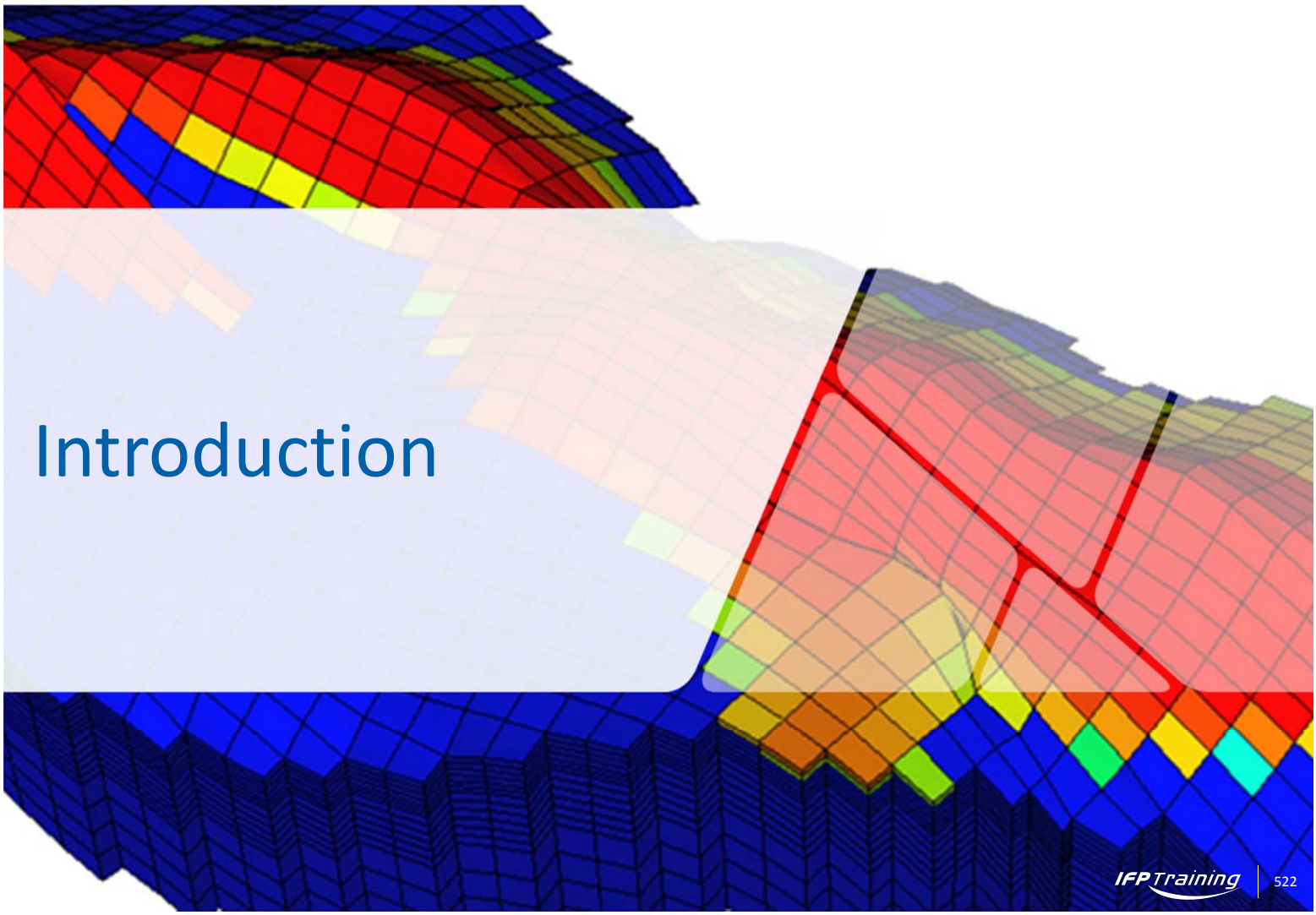


Reservoir simulation workshop
Production forecast

IFP Training

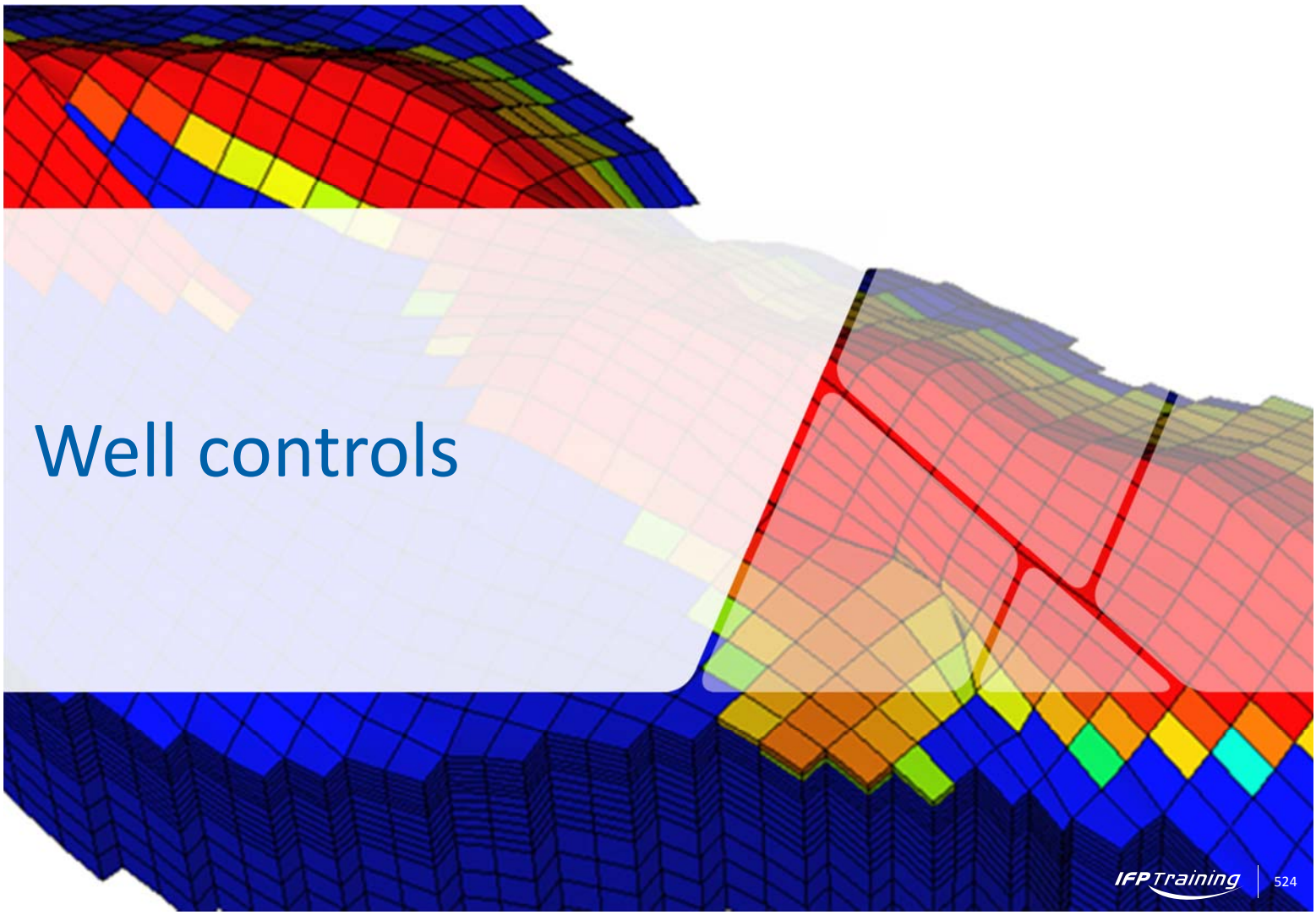
Production forecast

- Introduction 522
- Well controls 524
- Inflow & outflow calculations 528
- Matching of well performance 538



Introduction

- **Good Production forecasts will depend on**
  - Good history match
  - Good integration of well performance and production constraints
- **Well performance**
  - Inflow curves
    - Productivity index or complete curve
  - Outflow curves
    - VFP tables
- **Production constraints**
  - Constraints related to flow
    - Maximum water-cut or maximum GOR per well
    - Maximum water production or gas production for a group of wells
  - Constraints related to pressure
    - Minimum bottom hole flowing pressure
    - Minimum well head pressure



Well controls

Well Controls: principal uses in forecast mode

- **Main controls**
  - Imposed Flow rate
    - Oil, Water, Gas, Liquid, Reservoir voidage
  - Imposed pressure
    - Tubing Head Flowing pressure
    - Bottom hole flowing pressure
- **Secondary controls**
  - Flow rates
    - Economic limits
    - Rates upper limit per phase
    - Maximum ratios (Wcut, GOR, WGR)
  - Pressures
    - BHP and THP limit (lower for a producer, upper for an injector)
    - Maximum drawdown
- **VFP tables are used to relate bottom hole to well head pressures**

Well controls: ECLIPSE keywords

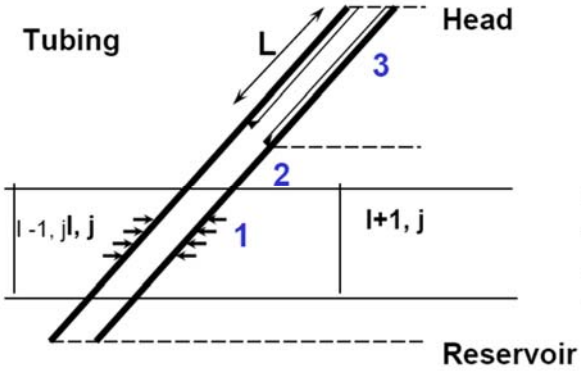
- **Well controls**
  - WCONPROD: Control data for a producer
  - WECON: Economic limit data for a producer
  - WELLDRAW: Set maximum drawdown per producer
  - WCONINJE: Control data for an injector
  - WECONINJ: Economic limit for an injector
- **VLP table**
  - VFPPROD: VFP tables for a producer
  - VFPINJ: VFP tables for an injector
- **Dimensions in RUNSPEC**
  - VFPPDIMS: Production wells VFP table dimensions
  - VFPIDIMS: Injection wells VFP table dimensions



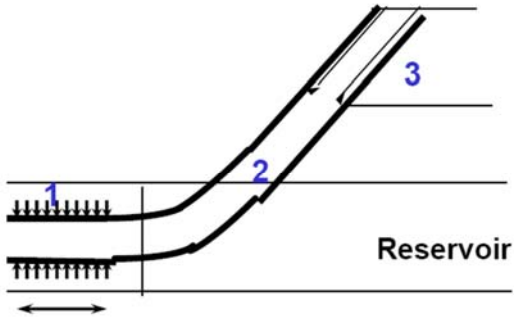
Inflow & outflow calculations

Inflow & Outflow calculations

- **Inflow**
  - Pressure drop between cell and bottom hole (section 1)
- **Outflow**
  - Pressure head between connection and datum of VFP table (section 2)
  - Head losses in tubing (section 3)



Deviated well



Horizontal well

Inflow & Outflow calculations

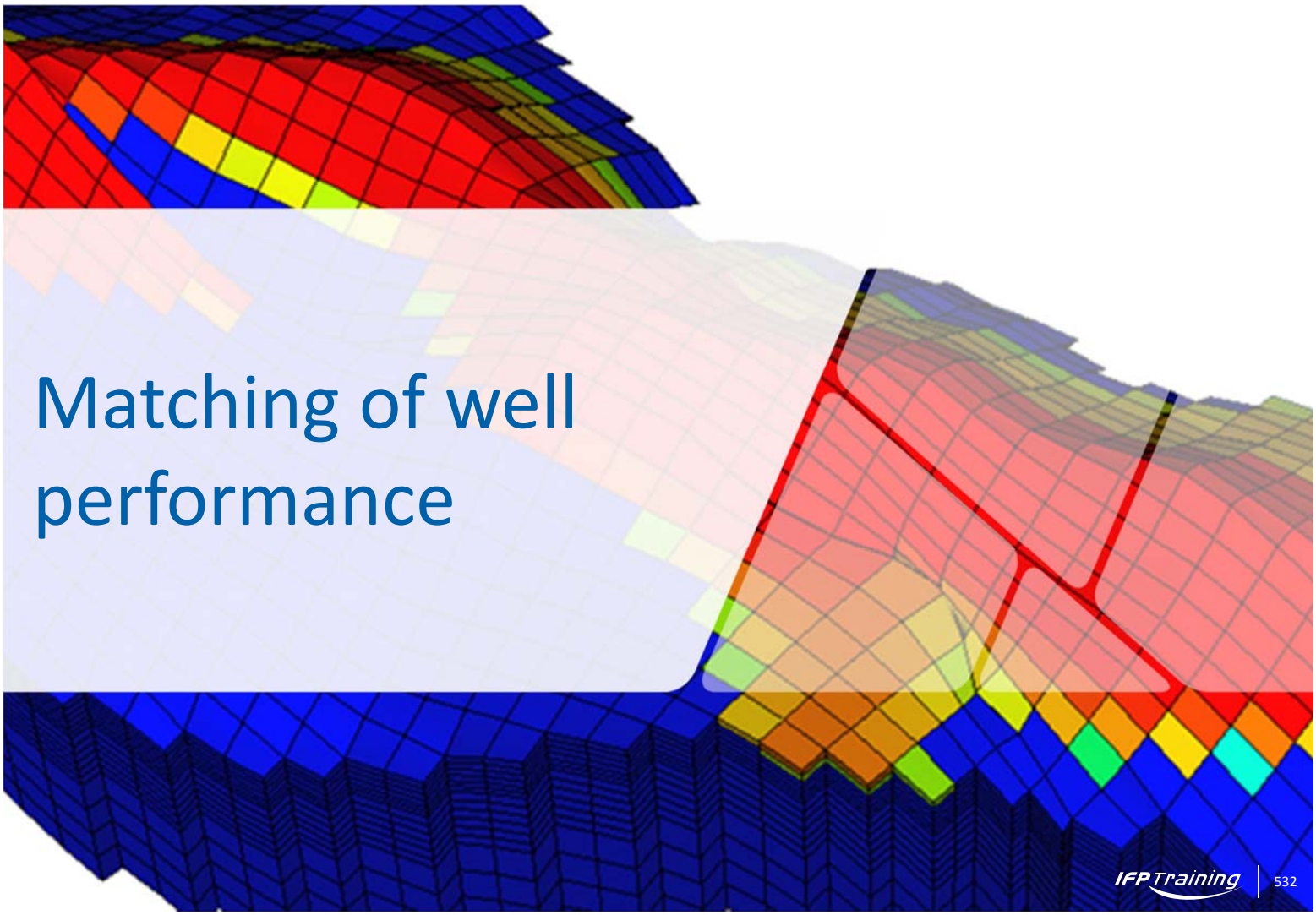
- **Inflow performance relationship (section 1)**

$$Q = CF\ x\ \frac{kr}{\mu}\ x\ (Pr\ -Pf)$$

- **Wellbore pressure head (section 2)**
  - Vertical well: hydrostatic head between the connection i and the well's datum + (correction up to VFP datum depth)
  - Horizontal well: hydrostatic head + friction if WFRIC or MSW
- **Pressure drop in tubing (section 3)**
  - Use of Vertical Flow Performance (VFP) tables provided in the data set
  - BHP = f (Q, THP, Wcut, GOR, Qlift)
- **Reminder**
  - It is important to define accurately the VFP tables when the inflow drawdown is low

Outflow calculations: VFP tables generation

- **VFP tables are generally generated by well department**
- **It is recommended**
  - To use the PVT corresponding to produced fluids
  - To generate one table for each value of tubing diameter
  - To group wells according to their deviation, completion and produced fluid
- **The parameters must cover the range of values which will be reached during the forecast simulations: NO EXTRAPOLATIONS!**
- **Some BHP may correspond to a combination of parameters physically impossible.**
  - Values higher than the max reservoir pressure should be given to ensure that the well flowing conditions will not enter the forbidden region



Matching of well performance

Matching of well performance

- **Well performance parameters are:**
  - Not used during history match (Wells are controlled in flow rate)
  - Used during production forecasts (Well flow rates are directly linked to well performance)
- **During history match**
  - It is pointless to try to match BHP and THP as long as reservoir pressure is not matched
  - It is highly recommended to match BHP and THP as soon as reservoir pressure is matched by introducing the VFP tables and adjusting PI
- **At the beginning of production forecasts**
  - BHP and THP must be matched per well to ensure the continuity from boundary conditions in flow (HM) to boundary conditions in pressure (forecast)

Matching of well performance: BHP per well

- **BHP per well can be modified by**
  - Tuning of Connection factors (CF)
  - Introduction of production uptimes
    - Use observed daily Q + WEFAC instead of monthly averaged Q
  - Use of WPIMULT or modification of the skin

- **Reminder: Tuning CF per layer may be necessary for PLT match**
  - The information provided by the PLT (allocation of flow per layer) must be taken into account since the match in P (K per layer)
  - It is recommended to adjust the skin per (group of) layers
  - Use instantaneous rates (not monthly averaged) and be sure that everything (P, measure conditions) is consistent

Matching of well performance: THP per well

- **BHP per well can be modified by**
  - Modification of the pressure head between connection and datum of VFP table
  - Modification of the VFP table
- **Eclipse solves for the intersection of:**
  - The linear portion of the VFP table at the flowing conditions (GOR and Wcut)
  - The local IPR: BHP = Pr - (Q /IP)
- **This intersection may be in the unstable part of the VFP curve; in this case the results are very sensitive to the slope of IPR**
- **It is recommended to discretise each parameter in VFP curves with enough values to represent correctly the working point**

Thank you for your attention!